MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

LETTER OF APPLICATION

IN THE MATTER OF: *The Crown Corporations Public Review & Accountability Act* (Manitoba)

IN THE MATTER OF: An Application by Manitoba Hydro for an Order of the Public Utilities Board Approving Increases to Electricity Rates

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

1. Manitoba Hydro hereby applies to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to *The Crown Corporations Public Review & Accountability Act* for the following:

   a) Approval, on an interim basis, of rate schedules incorporating an across-the-board 3.95% rate increase to all components of the rates for all customer classes effective April 1, 2015, sufficient to generate additional revenues of $57 million in 2015/16;

   b) Approval of a further 3.95% across-the-board rate increase to all components of the rates for all customer classes effective April 1, 2016, sufficient to generate additional revenues of $60 million in 2016/17;

   c) Final approval of Orders 49/14 and 51/14 which approved, on an interim basis, a 2.75% rate increase effective May 1, 2014 applied on an across-the-board basis, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to conclusion of this proceeding;

   d) Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class approved on an interim basis in Order 79/14;

e) Approval to implement Time-of-Use Rates for the General Service Large customer class served at greater than 30 kilovolts ("kV"), effective April 1, 2016, including the change in the definition of billing demand to be the highest measured on-peak demand in the month, 50% of contract demand or 50% of the highest on-peak demand in the previous 12 months;

f) Confirmation that the PUB accepts the rate approval process given proposed modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") as outlined in Tab 6 of this Application, that were approved on an interim basis in Order 43/13;

g) Confirmation that the PUB accepts the rate approval process given proposed modifications to the Curtailable Rate Program ("CRP"), as outlined in Tab 6 of this Application, that were approved on an interim basis in Order 43/13;

h) Final approval of all SEP interim *ex parte* rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

i) Final approval of CRP *ex parte* Order 46/14 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

j) Final approval of Orders 116/12 and 117/12 that approved, on an interim basis, a 6.5% rate increase to the full cost portion of the General Service and Government rates in the four remote communities served by diesel generation effective September 1, 2012, and final approval of diesel zone interim Orders 17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 148/11, subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement; and,

k) Approval to rescind the Demand Side Management deferral account established pursuant to Order 43/13 for the 2012/13 and 2013/14 fiscal years and on a go-forward basis.

2. Manitoba Hydro last filed a General Rate Application with the PUB on June 15, 2012 for the 2012/13 & 2013/14 fiscal years, which resulted in Order 43/13. This Order approved a 3.5% across-the-board general rate increase effective May 1, 2013, and directed that the revenues from a 1.5% portion of the increase accrue to an account to be utilized to mitigate the anticipated rate impacts when Bipole III is placed into service. Order 43/13 also provided final approval for Manitoba Hydro to maintain in its rates and revenues the 1% rate change that was previously approved by the PUB on an interim basis and subsequently rolled back in Order 5/12, final approval of the 2.0% interim rate increase granted in Orders 32/12 and 34/12 for April 1, 2012,

and final approval of the 2.4% interim rate increase granted in Orders 116/12 and 117/12 for September 1, 2012.

3. Subsequent to Order 43/13, Manitoba Hydro applied to the PUB for approval of an interim rate increase of 3.95% effective April 1, 2014, applied on an across-the-board basis to all customer classes. On May 5, 2014, the PUB issued Order 49/14 approving, on an interim basis, a 2.75% across-the-board general rate increase effective May 1, 2014, and directed that the revenues from a 0.75% portion of the increase accrue to the Bipole III deferral account established in Order 43/13. Subsequent to the issuance of Order 49/14, Manitoba Hydro filed a letter requesting the PUB to consider implementation of new LED rates for the Area and Roadway Lighting class on an interim basis effective August 1, 2014. This request was approved in Order 79/14.

4. By this Application, Manitoba Hydro is seeking approval, on an interim basis, of a 3.95% across-the-board general rate increase effective April 1, 2015 sufficient to generate additional revenue of $57 million in 2015/16, and a further across-the-board general rate increase of 3.95% effective April 1, 2016, sufficient to generate additional revenue of $60 million in 2016/17. The April 1, 2015 rate increase, if approved, would result in a $3.20 increase in the monthly bill of a residential customer without electric space heat using 1,000 kilowatt-hours ("kWh") per month, and a $6.11 increase in the monthly bill for a residential customer with electric space heat using 2,000 kWh per month. The April 1, 2016 rate increases, if approved, would result in a $3.33 increase in the monthly bill of a residential customer without electric space heat and a $6.36 increase in the monthly bill for a residential customer using electricity for space heat. For rates effective April 1, 2016, Manitoba Hydro is also requesting approval to implement TOU rates for the General Service Large customer class served at greater than 30 kV.

5. This Application provides prima facie support to provide the rate relief requested in this Application effective April 1, 2015. The subsequent regulatory process and public hearing will allow the PUB to confirm the interim rate increase and review the request for a further rate increase effective April 1, 2016. Approval of the rate increases proposed in this Application is required to maintain net income and financial ratios for 2015/16 and 2016/17 at acceptable levels. Absent the requested rate increases, Manitoba Hydro is projecting that over the 2015/16 and 2016/17 fiscal years, there would be no cumulative contribution to financial reserves and that financial ratios would deteriorate below acceptable levels. In making this Application, Manitoba Hydro has considered customer sensitivity to rate increases as well as the financial position of the Corporation, and believes the proposed rate increases are the minimum necessary in order to promote rate stability for customers and ensure the financial integrity of the Corporation.

6. The circumstances giving rise to the rate increases will be discussed in Tab 2 of the Application. Further information in support of the Application will be provided in Tab 3 to Tab 9 of the Application. In addition, Manitoba Hydro will address the responses to a number of PUB directives in Tab 10 of the Application.

Communication related to this Application should be addressed to Manitoba Hydro in the following fashion:

Manitoba Hydro
Attention: Odette Fernandes
22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Telephone No. (204) 360-3633
Fax No. (204) 360-6147
E-Mail: ofernandes@hydro.mb.ca

DATED at Winnipeg, Manitoba this 16th day of January, 2015.

MANITOBA HYDRO

"ORIGINAL SIGNED
BY ODETTE FERNANDES"

Per: ______________________
Odette Fernandes

MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

OVERVIEW & REASONS FOR APPLICATION

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MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

OVERVIEW & REASONS FOR APPLICATION

2.0 OVERVIEW

The purpose of Tab 2 is to provide an overview of Manitoba Hydro's 2015/16 & 2016/17 General Rate Application and summary of the reasons for the Application.

Manitoba Hydro has a long history of providing safe, clean, reliable energy to Manitoba communities, households and businesses; energy that has fueled prosperity and economic growth in the province.

Manitoba Hydro also takes great pride in providing Manitobans with reliable service and some of the lowest electricity rates in North America. Manitoba Hydro has maintained stable rates through careful management of its assets, prudent spending on capital projects, and by managing its operating and administrative costs.

Today, Manitoba Hydro must invest in the system that has served customers for decades to ensure that it can continue to deliver safe, clean, reliable energy to Manitobans for generations to come. This required investment will mean that rates will need to increase gradually over the next decade to pay for these investments, and Manitoba Hydro believes that the rate increases proposed in this General Rate Application carefully balances the need for investment with the need to provide ratepayers with steady, predictable rates.

The key reasons for the Application are:

1. Manitoba Hydro is entering a period of extensive capital investment to meet the growing energy requirements of Manitoba, to replace aging utility assets and address increased capacity needs on the system.

2. While a portion of the required investments will be funded by cash flow from operations, the majority will be funded through unprecedented levels of debt financing.

3. The requirement for the proposed rate increases are primarily being driven by the required investments, which are expected to double the asset base and carrying costs (finance expense, depreciation and amortization expense and capital taxes) of Electric operations in the next 10 years.

4. Rate stability for customers is dependent on Manitoba Hydro maintaining its financial strength. The required investment in assets will place pressure on Manitoba Hydro's financial strength by deteriorating the financial results and key financial ratios.

5. The following significant risks are associated with rate increases lower than 3.95%:
    i. Increased risk to customers of rate instability and rate shock;
    ii. Increased risk to customers of decreases in service and reliability;
    iii. Increased borrowing requirements and associated financing costs, which will ultimately be recovered from customers;
    iv. Potential negative implications to the Provincial credit rating and Manitoba Hydro's borrowing costs.

6. Manitoba Hydro is committed to effectively controlling its OM&A costs and managing these costs below inflationary levels (excluding accounting changes that impact OM&A), during a time of significant and increasing cost pressures. This will assist in maintaining the 3.95% proposed rate increases.

7. The proposed 3.95% rate increases are the minimum that are required to maintain:
    i. A reliable energy supply to Manitobans, to which they are accustomed, and fund Power Smart Programs to assist customers in meeting their energy needs.
    ii. Rate stability and manage the deterioration in the Corporation's financial strength during the period of extensive capital investments.
    iii. Manitoba Hydro's 2015/16 and 2016/17 net income and financial ratios at acceptable levels.

2.1 MANITOBA HYDRO'S CORPORATE PROFILE & STRATEGIC DIRECTION

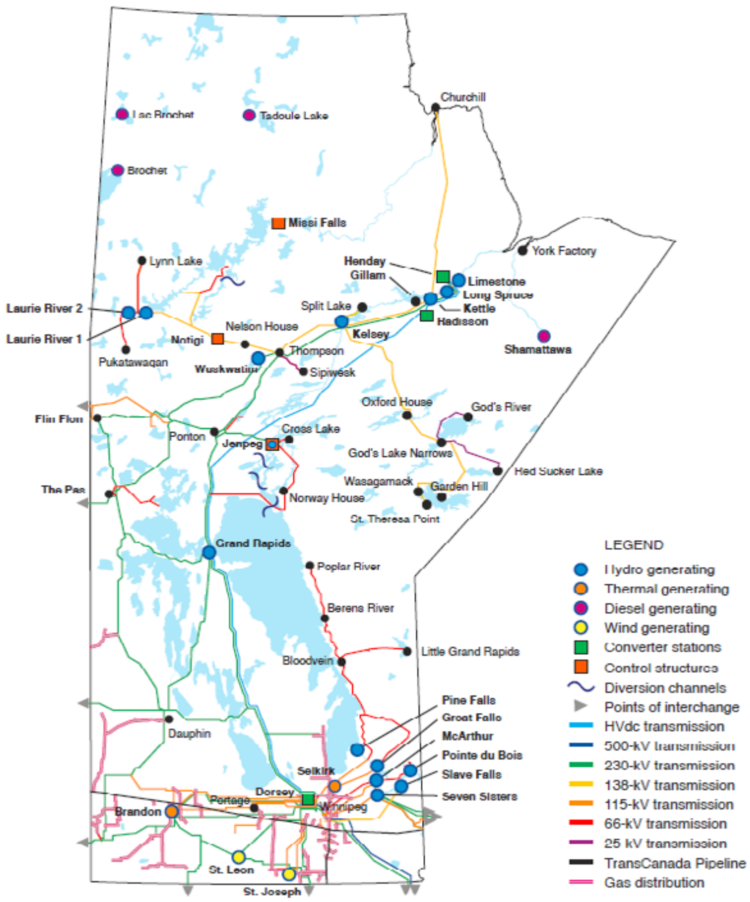
2.1.1 Corporate Profile

Manitoba Hydro is a provincial Crown Corporation governed by the Manitoba Hydro-Electric Board, whose members are appointed by the Lieutenant-Governor in Council. With over $16 billion in assets at historic cost, Manitoba Hydro is one of the largest integrated electricity and natural gas distribution utilities in Canada, with 5,725 megawatts of installed capacity. Manitoba Hydro serves over 555,000 electricity customers across Manitoba and 272,000 natural gas customers in the southern part of the province.

Manitoba Hydro has a long history of providing reliable energy to communities, households and businesses in Manitoba and operating one of the cleanest, most sustainable power systems in North America. Nearly all of the electricity Manitoba Hydro typically produces each year (approximately 98% on an energy basis) is clean, renewable water power generated at 15 hydro-electric generating stations. As part of it electrical system, Manitoba Hydro operates and maintains 13,000 kilometers of electric transmission lines, and 76,000 kilometers of electric distribution lines throughout the Province. Manitoba Hydro also maintains two thermal generating stations to back up its hydro-electric system and purchases electricity from two independent wind farms.

The following figure depicts Manitoba Hydro's major electrical and gas facilities.

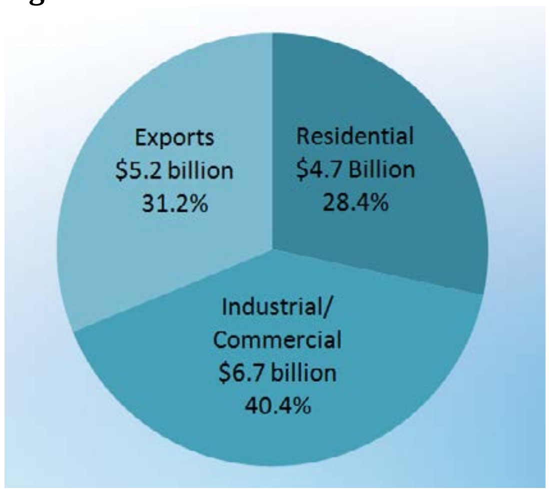
Figure 2.1: Major Electrical and Natural Gas Facilities



Manitoba Hydro's ongoing operations and future projects represent a major contributing factor to the provincial economy, translating to employment and business opportunities for thousands, especially in the northern regions where much of the new development is taking place.

In addition to providing electricity to Manitobans, Manitoba Hydro exports surplus electricity to utilities within three wholesale markets in the Midwestern U.S. and Canada. In the last decade, export sales have contributed $5.2 billion in revenues to Manitoba Hydro. These revenues are used to keep rates low for Manitobans.

Figure 2.2: Share of Total Electric Revenue 2005-2014



2.1.2 Corporate Strategic Plan

Manitoba Hydro's Corporate Strategic Plan ("CSP") is summarized in the following figure and sets out the Corporation's vision and mission, and outlines key objectives focused on meeting Manitobans' long-term energy needs and achieving operational excellence in electric and gas operations.

Figure 2.3: Manitoba Hydro Vision, Mission and Key Areas of Focus

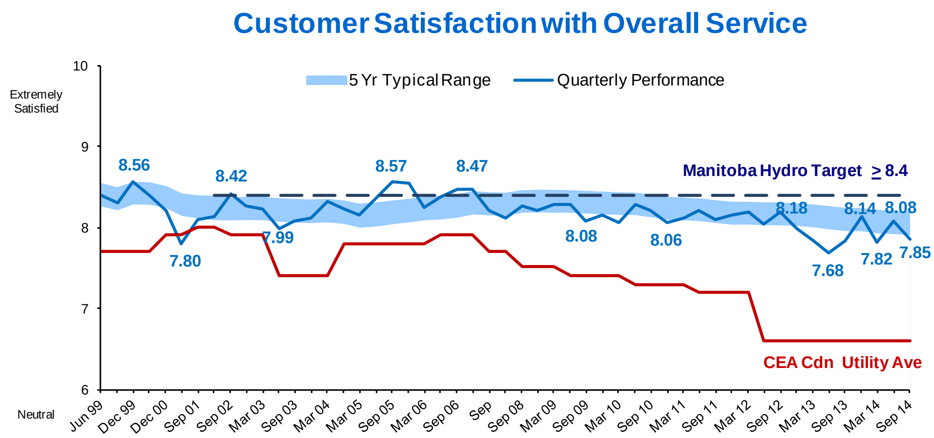
A full copy of Manitoba Hydro's current CSP is provided as Appendix 2.1 to this Tab.

Using the CSP as a guide, Manitoba Hydro's business units develop supporting business objectives that establish priorities, and outline strategies and measures designed to contribute towards achieving overall corporate objectives. To accomplish these objectives, Manitoba Hydro is organized into 10 business units. A description of each Business Unit and Manitoba Hydro's current Organizational Chart is provided in Appendix 2.2.

2.1.3 Manitoba Hydro is a Leader in Customer Satisfaction

An industry leader in customer satisfaction, Manitoba Hydro is committed to providing high system reliability, excellent customer service and affordable rates. Manitoba Hydro continues to receive satisfaction ratings for customer service, corporate citizenship and corporate image components that are consistently higher than the national average for Canadian electric utilities. Manitoba Hydro's customer satisfaction results compared to the CEA Canadian Average are shown in the following figure.

Figure 2.4: Customer Satisfaction with Overall Service



2.1.4 Manitoba Hydro Provides High System Reliability

Electricity is essential to the lives and livelihoods of Manitobans and is a contributor to the prosperity of Manitoba's economy. The investment in electric infrastructure that Manitoba Hydro has made over decades has resulted in one of the most reliable, sustainable and affordable power systems in Canada. The following figures show that Manitoba Hydro has historically been in the first quartile of CEA member utilities as it relates to the System Average Interruption Frequency Index ("SAIFI") and the System Average Interruption Duration Index ("SAIDI") reliability indicators, on a calendar year basis. The SAIFI indicator measures the average number of interruptions that a customer has experienced, and the SAIDI indicator measures the average outage duration experienced by customers.

Figure 2.5: Manitoba Hydro SAIFI Indicator Compared to CEA Member Utilities

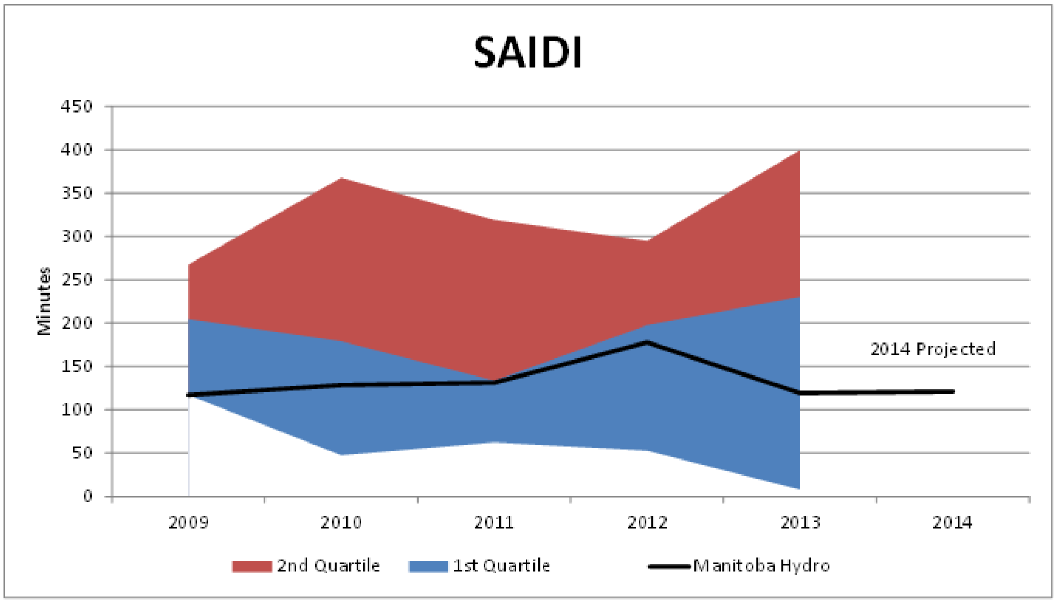
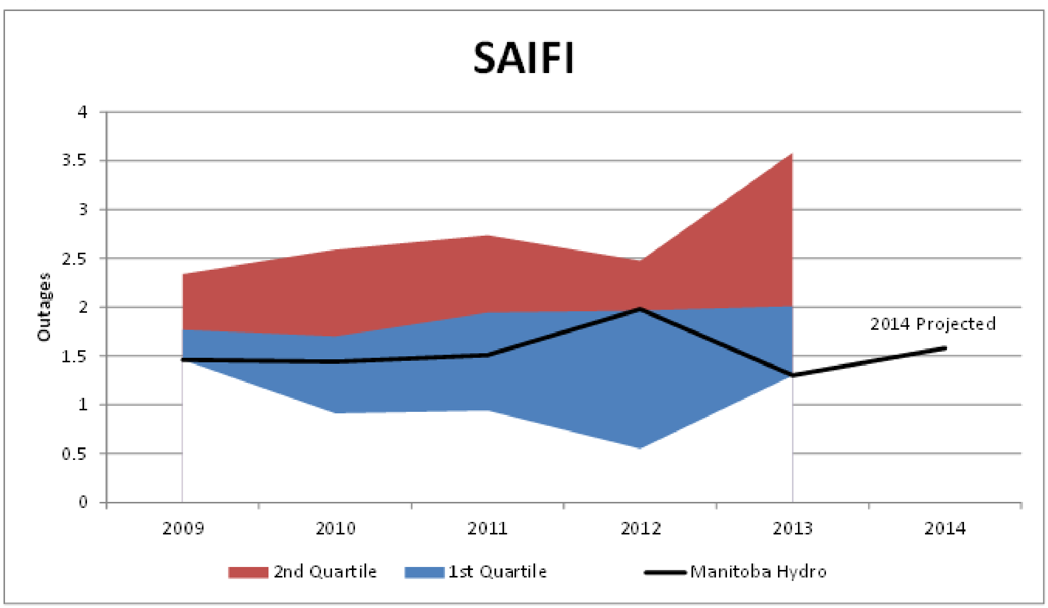


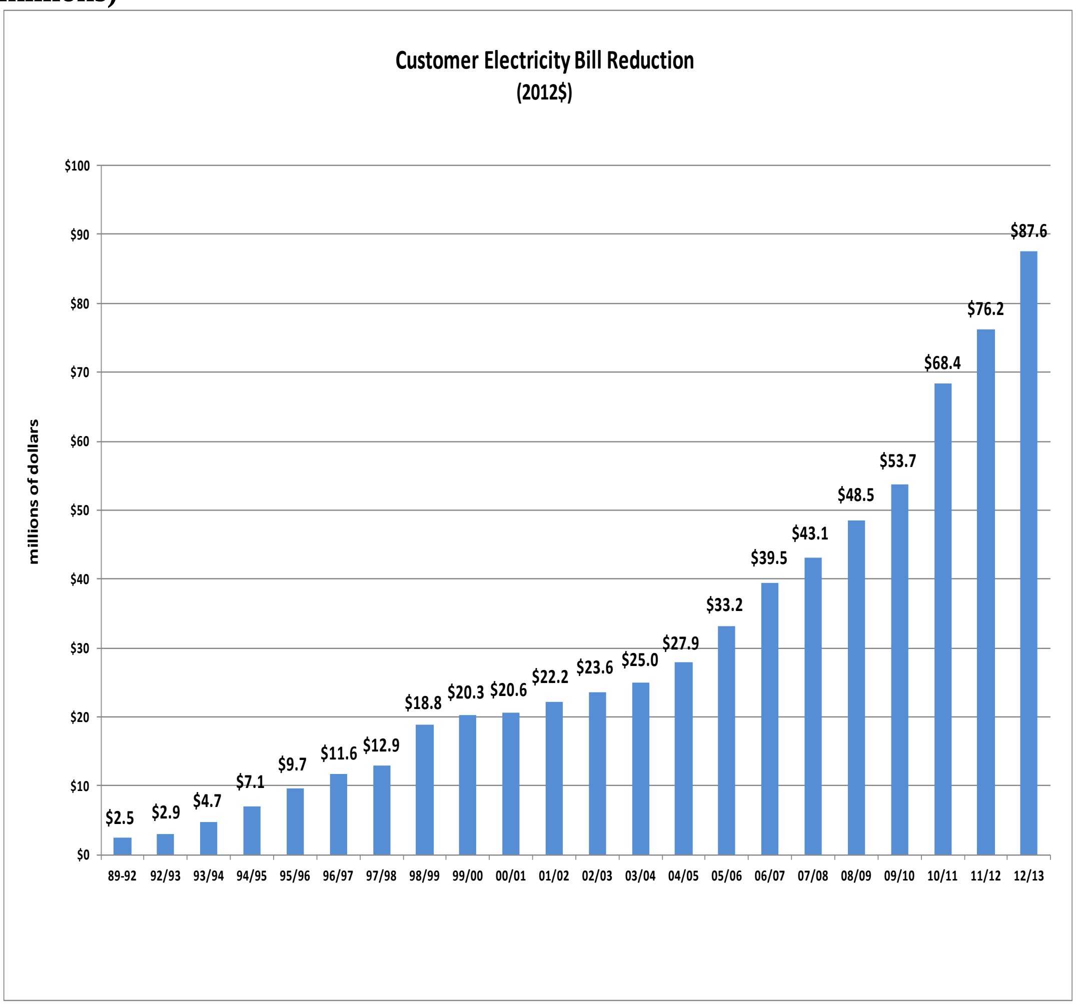
Figure 2.6: Manitoba Hydro SAIDI Indicator Compared to CEA Member Utilities



2.1.5 Manitoba Hydro is a Leader in Offering Power Smart Programs

Manitoba Hydro's Power Smart Programs have been and continue to be very successful at reducing customers' energy bills while contributing to a sustainable energy supply in Manitoba. As demonstrated in the following figure, Power Smart electrical savings translate into a growing annual reduction in customer electricity bills with a total of $660 million cumulative reduction to 2012/13. In addition, Power Smart has led to reductions in indirect greenhouse gas emission reductions of approximately 1,532,000 tonnes of carbon dioxide equivalent emissions in 2012/13.

Figure 2.7: Annual Power Smart Savings—Customer Electricity Bill Reduction ($ millions)

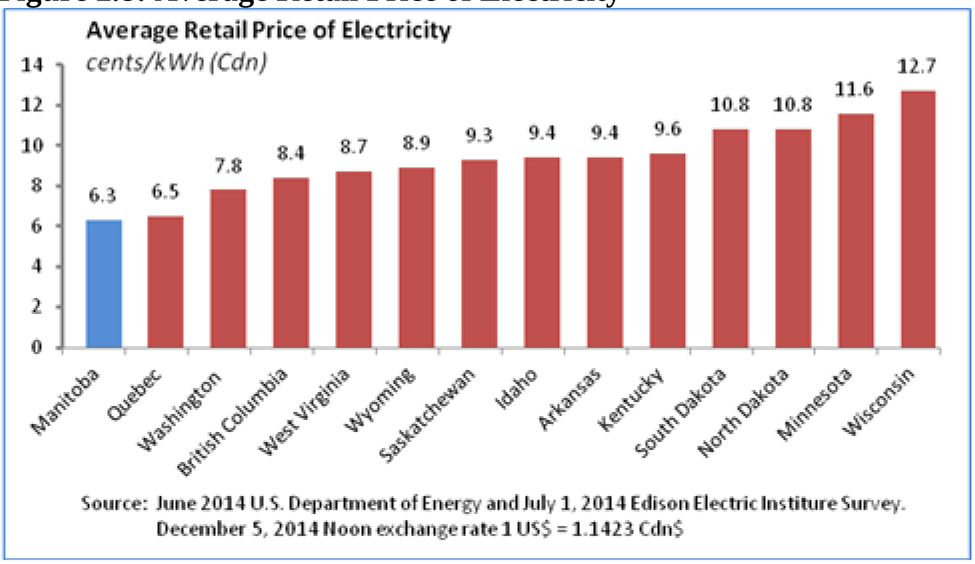


2.1.6 Manitoba Hydro Offers Affordable and Competitive Rates to Customers

Manitoba Hydro's domestic electric rates are affordable for Manitoba families and support the competitiveness of Manitoba businesses. The following figure shows

Manitoba Hydro's current weighted-average retail electricity price for all customer classes (as compared to other low-cost jurisdictions and neighbouring utilities), and demonstrates that Manitoba Hydro has among the lowest average retail electricity rates in North America.

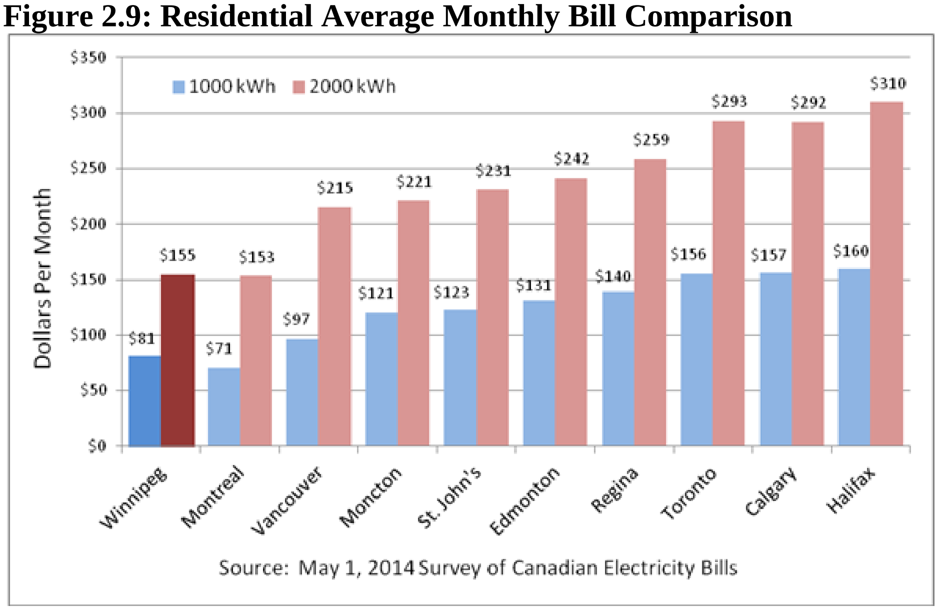
Figure 2.8: Average Retail Price of Electricity



Source: June 2014 U.S. Department of Energy and July 1, 2014 Edison Electric Institute Survey.
December 5, 2014 Noon exchange rate 1 US$ = 1.1423 Cdn$

As is demonstrated in the following figure, Manitoba enjoys a distinct advantage over most of the Canadian jurisdictions with respect to the average monthly bills of residential customers.

Figure 2.9: Residential Average Monthly Bill Comparison



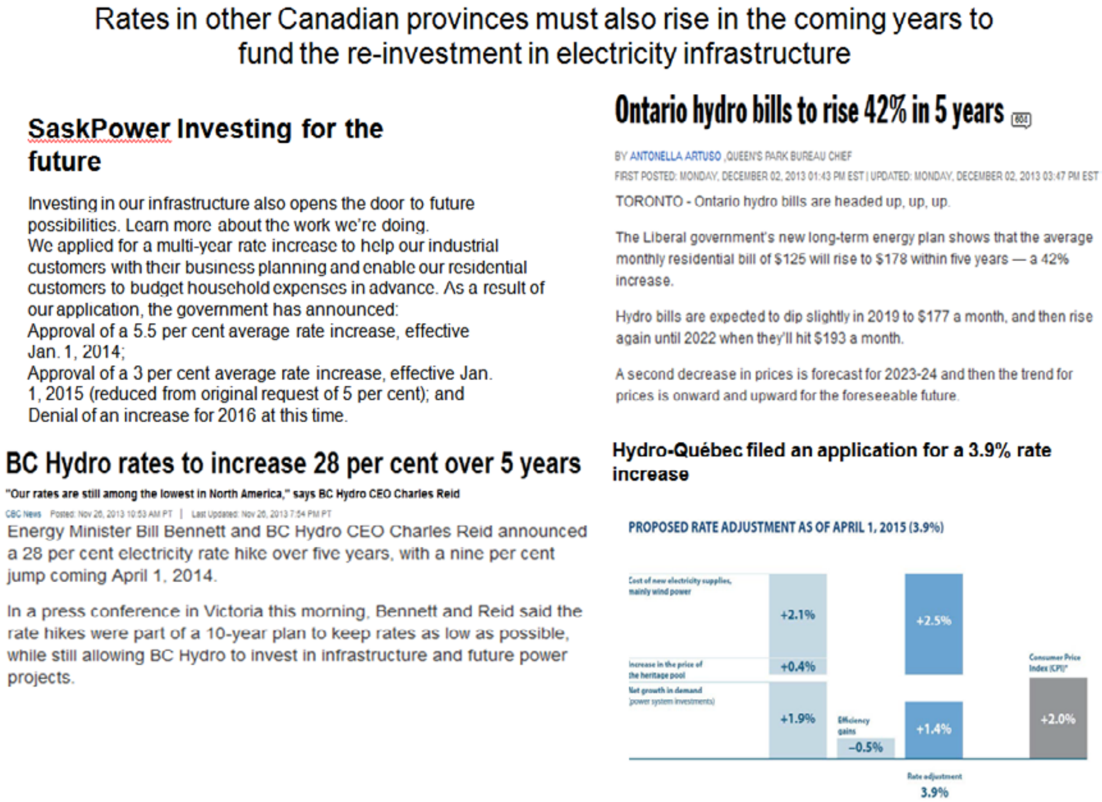
Source: May 1, 2014 Survey of Canadian Electricity Bills

The April 1, 2015 rate increase, if approved, would result in a modest $3.20 increase in the monthly bill of a residential customer without electric space heat using 1,000 kilowatt-hours (“kWh”) per month, and a $6.11 increase in the monthly bill for a residential customer with electric space heat using 2,000 kWh per month.
The April 1, 2016 rate increases, if approved, would result in an additional $3.33 increase in the monthly bill of a residential customer without electric space heat and an additional $6.36 increase in the monthly bill for a residential customer using electricity for space heat.

It is recognized that other Canadian utilities are also encountering the need to replace and refurbish aging utility assets, which will place upward pressure on electricity rates across most jurisdictions in the coming years. As can be seen in the following charts, Manitoba Hydro is not alone in needing to address the required investment in its electrical system through higher rate increases.

Figure 2.10: Required Investment in Canada’s Electricity System 2011-2030

Figure 2.11: Proposed Rate Increases in Other Jurisdictions



Rates in other Canadian provinces must also rise in the coming years to fund the re-investment in electricity infrastructure

SaskPower Investing for the future

Investing in our infrastructure also opens the door to future possibilities. Learn more about the work we're doing.
We applied for a multi-year rate increase to help our industrial customers with their business planning and enable our residential customers to budget household expenses in advance. As a result of our application, the government has announced:
Approval of a 5.5 per cent average rate increase, effective Jan. 1, 2014;
Approval of a 3 per cent average rate increase, effective Jan. 1, 2015 (reduced from original request of 5 per cent); and
Denial of an increase for 2016 at this time.

BC Hydro rates to increase 28 per cent over 5 years

"Our rates are still among the lowest in North America," says BC Hydro CEO Charles Reid

CBC News Posted: Nov 26, 2013 10:53 AM PT | Last Updated: Nov 26, 2013 7:54 PM PT

Energy Minister Bill Bennett and BC Hydro CEO Charles Reid announced a 28 per cent electricity rate hike over five years, with a nine per cent jump coming April 1, 2014.

In a press conference in Victoria this morning, Bennett and Reid said the rate hikes were part of a 10-year plan to keep rates as low as possible, while still allowing BC Hydro to invest in infrastructure and future power projects.

Ontario hydro bills to rise 42% in 5 years

BY ANTONELLA ARTUSO, QUEEN'S PARK BUREAU CHIEF
FIRST POSTED: MONDAY, DECEMBER 02, 2013 01:43 PM EST | UPDATED: MONDAY, DECEMBER 02, 2013 03:47 PM EST

TORONTO - Ontario hydro bills are headed up, up, up.

The Liberal government's new long-term energy plan shows that the average monthly residential bill of $125 will rise to $178 within five years — a 42% increase.

Hydro bills are expected to dip slightly in 2019 to $177 a month, and then rise again until 2022 when they'll hit $193 a month.

A second decrease in prices is forecast for 2023-24 and then the trend for prices is onward and upward for the foreseeable future.

Hydro-Québec filed an application for a 3.9% rate increase

While Manitoba Hydro will be required to gradually increase rates to pay for its increased investment in generation, transmission and distribution infrastructure, the electrical rate advantage enjoyed by energy consumers in Manitoba over those in most other jurisdictions is expected to continue.

2.2 MANITOBA HYDRO'S CAPITAL INVESTMENT DRIVERS & BORROWING REQUIREMENTS

2.2.1 Manitoba Hydro is Entering a Period of Extensive Capital Investment

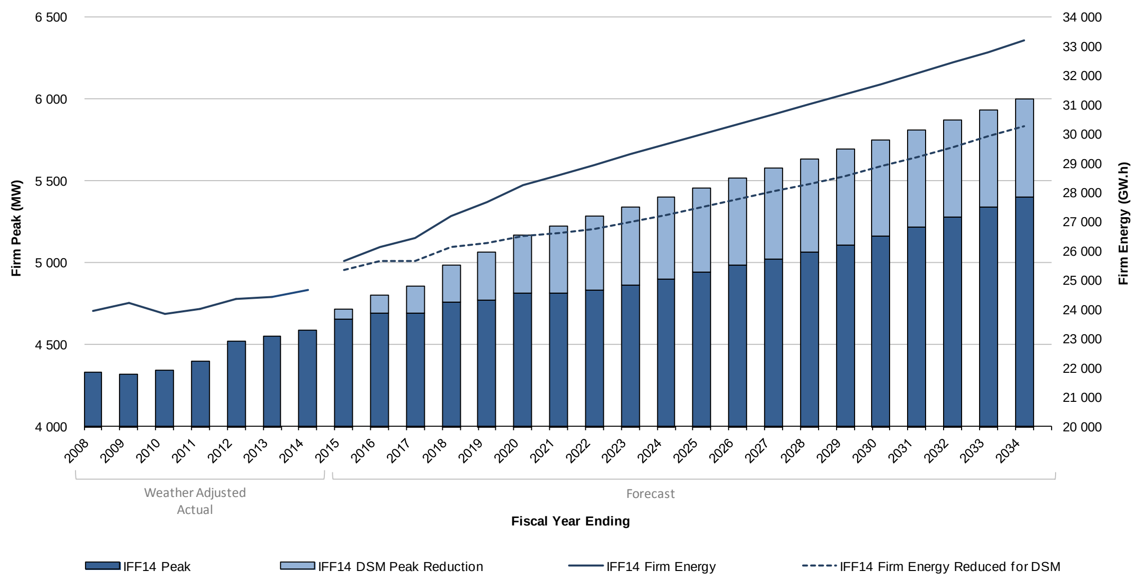
The provision of electric service is inherently a capital intensive business which requires a substantial investment in generating stations, transmission lines, distribution facilities and supporting infrastructure. Another characteristic of an electric utility is that the investments in major projects are large and lumpy and tend to have a significant impact on revenue requirements when they are first placed into service. In order to provide safe and reliable service to customers, Manitoba Hydro is continuously investing in assets.

Manitoba Hydro is entering a period of extensive investment and re-investment in its infrastructure in order to meet the growing energy needs of Manitoba, to replace aging utility assets that are approaching the end of their service lives, and to address capacity constraints on its existing system. The required infrastructure investment costs will be many multiples higher than the historic cost of the existing asset base.

Manitoba Hydro is also committed to significantly higher levels of investment in Demand Side Management ("DSM") programs on behalf of customers. Manitoba Hydro's Power Smart Programs play a key role in meeting Manitoba's future energy needs in a sustainable manner and assisting customers in reducing their energy bills by using energy more efficiently.

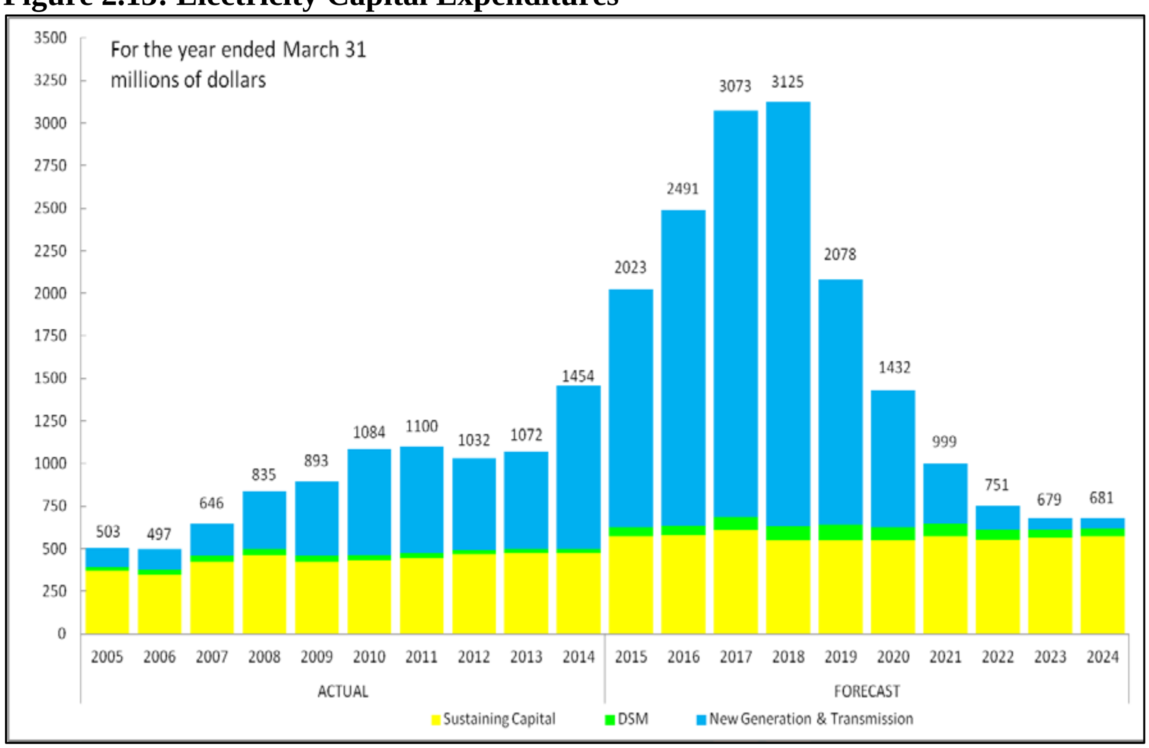
Even with load reductions from Power Smart initiatives, the demand for electricity in Manitoba is continuing to grow as a result of increases in population, higher average energy usage, and industrial and commercial customer expansion. The following figure shows the actual and forecast growth in Manitoba Hydro's load, as well as the forecasted impact of the Power Smart Plan.

Figure 2.12: Forecast Load Growth Before and After Impact of DSM



The required investment in new and replacement assets, as well as DSM programs, will result in significantly higher capital expenditures over the next 10 year period, as demonstrated by the following figure.

Figure 2.13: Electricity Capital Expenditures

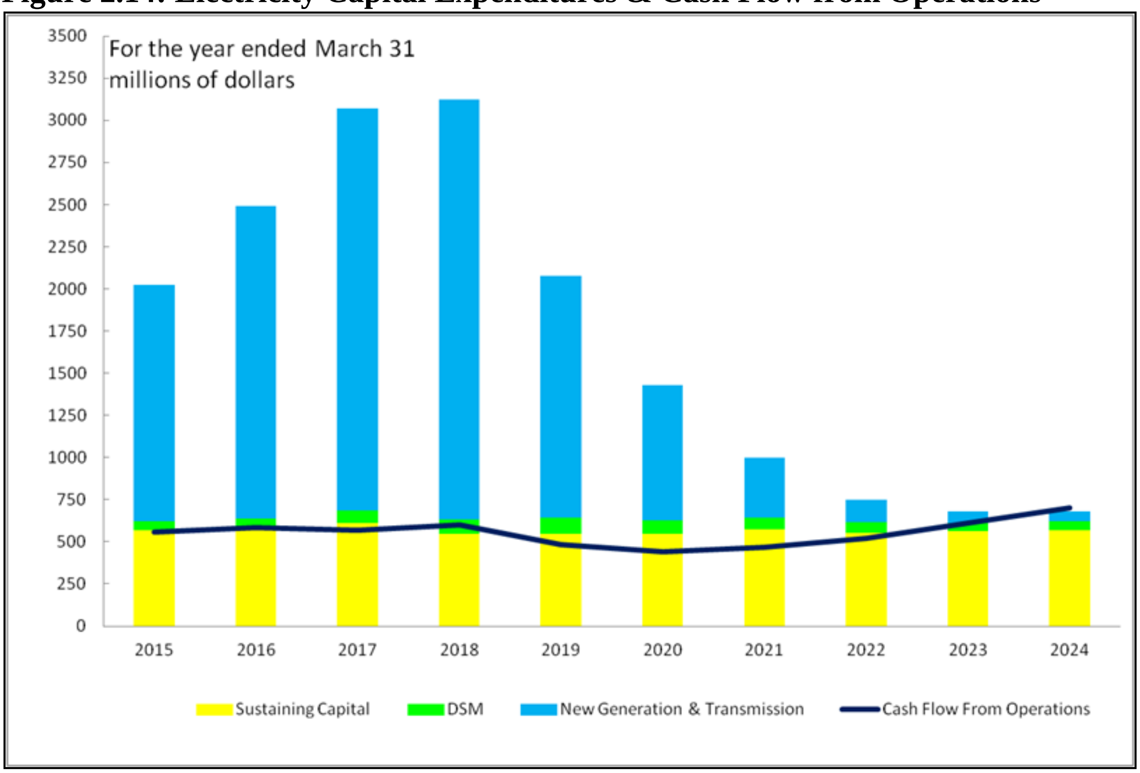


2.2.2 Investment Requirements will Lead to Unprecedented Levels of Debt Financing

Unlike private utilities, Manitoba Hydro does not have access to share capital as a source of funds and must rely on a combination of internally generated cash from operations and debt financing in order to fund its capital investment program.

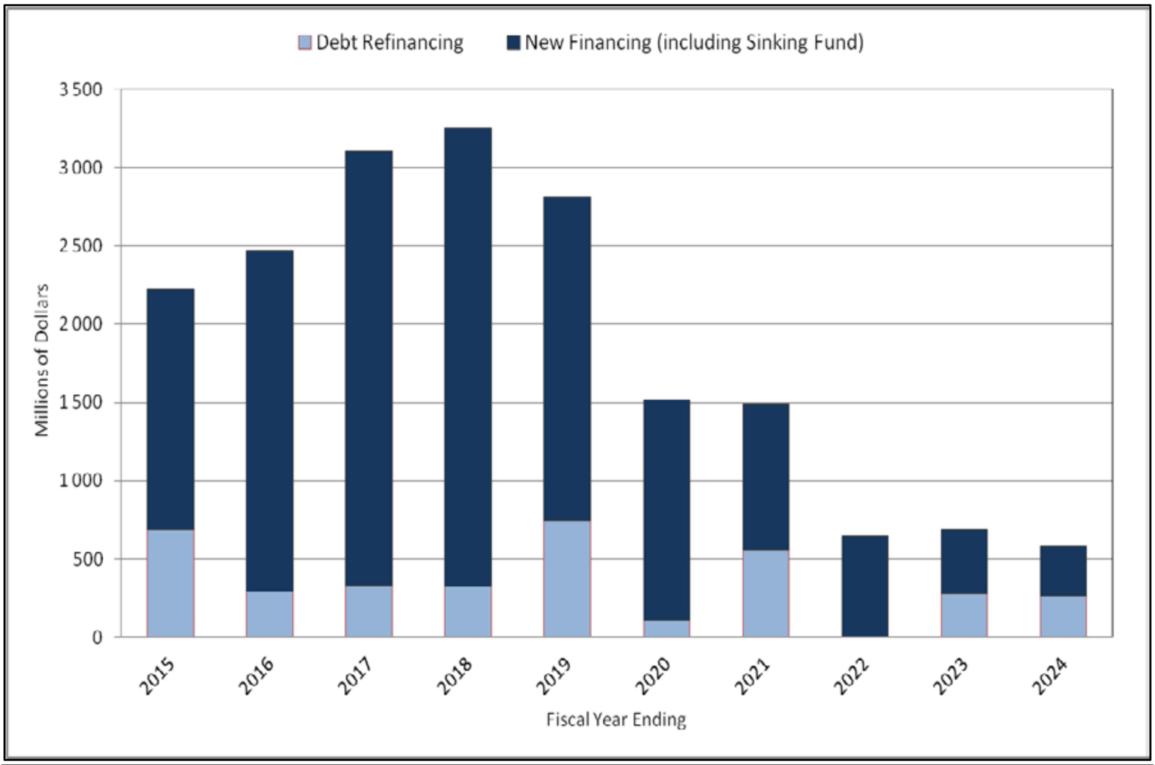
The following figure depicts the capital investment requirements for the next 10 years along with the forecasted cash-flow from operations, including the proposed and indicative 3.95% rate increases. Manitoba Hydro has historically targeted to fund sustaining capital expenditures with cash flow from operations. This chart indicates that the cash that is projected to be generated from operations is just sufficient in 4 of the 10 years to fund sustaining capital expenditures. From 2019 to 2022, Manitoba Hydro is projecting that it will be required to borrow funds to finance sustaining capital expenditures.

Figure 2.14: Electricity Capital Expenditures & Cash Flow from Operations



The implications of the above-noted figure is that Manitoba Hydro is forecasting that in the next 10 years it will fund the vast majority of new major generation and transmission capital expenditures through debt financing. When combined with debt refinancing requirements, the total debt requirements for Manitoba Hydro's electric operations in the next five-year period will peak at levels in excess of $3 billion per year, as illustrated in the following figure. These total forecast debt requirements are unprecedented in Manitoba Hydro's history.

Figure 2.15: Projected Electric Operations Borrowing Requirements



The proposed and indicative rate increases are necessary to stabilize Manitoba Hydro's cash flow from operations to the minimum level to fund the majority of sustaining capital expenditures thereby avoiding: higher levels of debt; higher cash flow requirements to pay the interest on the incremental debt; higher interest expense; and higher customer rates, all to the benefit of the customer.

2.3 THE COMPELLING NEED FOR RATE INCREASES

In the previous section, Manitoba Hydro described the business requirements that are driving the need for investments in assets to allow the Corporation to continue to provide safe and reliable service to customers. In this section, Manitoba Hydro will describe how these same investments will impact revenue requirements and necessitate the requested rate increases.

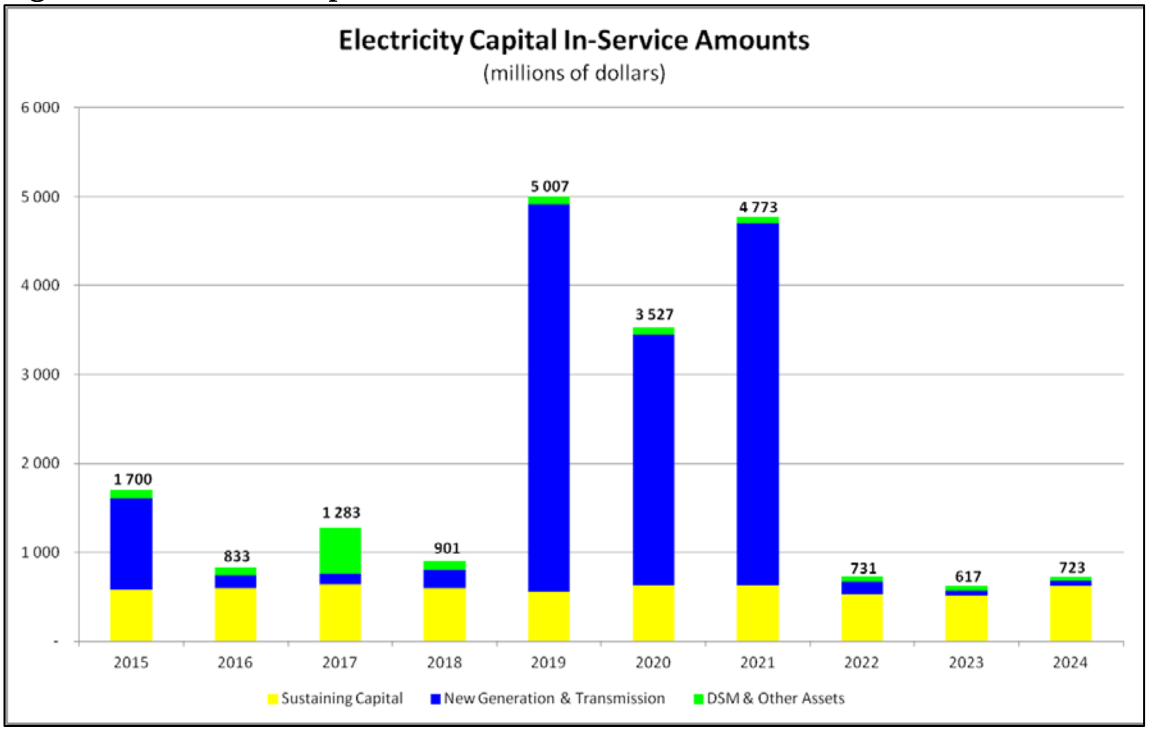
2.3.1 Revenue Requirements are Driven by Assets Being Placed into Service

As a result of the capital intensive nature of Manitoba Hydro's business, a significant portion of the overall revenue requirement of the Corporation is made up of carrying costs (finance expense, depreciation, and capital taxes) of the assets that are utilized to provide service to customers, along with the operating and maintenance costs of these assets. While assets are under construction, the capital expenditures and associated financing costs are held in construction work in progress. Once these assets are placed into service, the associated carrying costs form part of the Corporation's revenue requirements.

As is demonstrated in the Figure 2.16, the annual amount of assets that are forecast to be placed in service for electric operations will range between $0.6 billion and $5.0 billion over the next 10 year period. In the three year period for which rates are being reviewed as part of this Application (2015-2017), it is forecast that $3.8 billion of assets will be placed into service or commence amortization. The most significant assets being placed in-service during this period include the Pointe du Bois spillway replacement, and the Riel 230/500kV Station in 2015. In this three year period, there is also approximately $1.8 billion of sustaining capital expenditures that will be placed into service, and $0.2 billion of DSM expenditures that will commence amortization.

Over the 10 year period between 2015 to 2024, it is projected that $20.1 billion of assets will be placed into service related to electric operations, the most significant of which are the Bipole III Reliability Project ($4.6 billion) and the Keeyask Generating Station ($6.5 billion). In this 10 year period, it is projected that approximately $5.9 billion of sustaining capital expenditures will be placed into service, $0.7 billion of DSM expenditures will commence amortization and $0.4 billion of deferred Conawapa costs will commence amortization.

Figure 2.16: Electric Capital In-Service 2015-2024

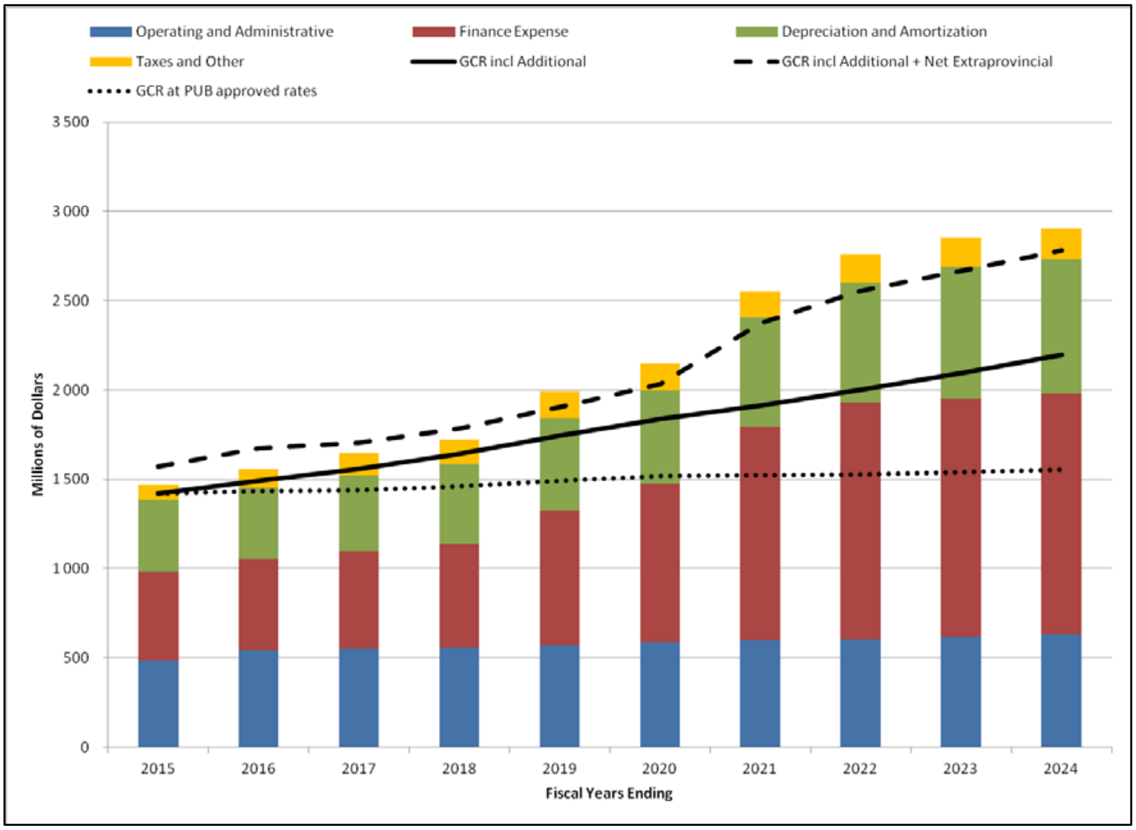


2.3.2 Carrying Costs on Electric Assets are Expected to Double in Next 10 Years

The required investment in new and existing infrastructure is expected to double the asset base and associated carrying costs of electric operations in the next 10 years.

The graph below provides a depiction of the increase in the costs for electric operations over the next 10 year period compared to the revenues that are projected to be generated from domestic and export customers.

Figure 2.17: Electric Expenses Compared to Revenues



The bars in Figure 2.17 provide the projected operating & administrative expense (blue bar), finance expense (red bar), depreciation & amortization expense (green bar), and taxes and other costs (orange bar) for the next 10 year period. Over that period, the total costs of the electric operations are projected to increase from the current level of approximately $1.5 billion to nearly $3.0 billion. The increase in costs in the years that are under review in this Application (2015-2017), and in the next 10 years are primarily related to increases in finance expense and depreciation as a result of the assets that are coming into service. Operating, maintenance and administrative costs are relatively constant throughout this period and do not materially contribute to the $1.5 billion increase in electric costs.

The dotted line in the Figure 2.17 represents domestic general consumers' revenue (GCR) at current PUB approved rates and the solid line represents GCR including the proposed and indicative rate increases of 3.95% per year to 2023/24. The dashed line in the graph represents the total of GCR at the proposed rates including rate increases and net extra-provincial revenues (extra-provincial revenues net of water rentals and fuel and power purchased).

Even with the proposed and indicative rate increases, Manitoba Hydro is projecting losses on electric operations in 2018/19 to 2023/24 totaling approximately $900 million as forecast domestic and export revenues will not be sufficient to cover the increased costs.

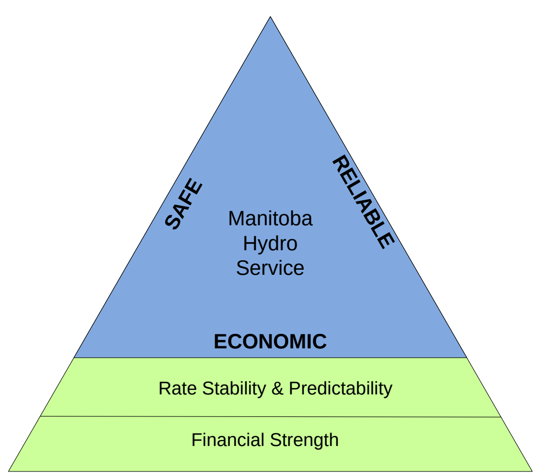
In the next 10 years there is significant financial risk and potential for rate volatility as Manitoba Hydro's financial position deteriorates due to the large investment requirements. In the longer term, the indicative 3.95% rate increases and export revenues generated from the Keeyask Generating Station are projected to accumulate to a sufficient level to cover the increased costs and Manitoba Hydro will begin to rebuild its financial reserves.

2.3.3 Rate Stability for Customers is Dependent on the Financial Strength of the Corporation

In order to ensure rate stability and predictability for customers, it is necessary that Manitoba Hydro maintains its financial strength. In other words, if Manitoba Hydro does not receive the necessary rate increases to maintain its financial strength, then there is significant risk to customers that rate changes will become more volatile and there will be a need for sudden or larger rate increases in the near future. This risk is particularly acute in the upcoming period of extensive capital investment and reinvestment.

Manitoba Hydro's safe, reliable and economic service is based upon a solid foundation of financial strength which promotes rate stability and predictability for customers.

Figure 2.18: The Foundation of Safe, Reliable and Economic Service



2.3.4 Investments in Capital Assets Will Place Pressure on Manitoba Hydro's Financial Strength

The proposed and indicative rate increases are the minimum rate increases necessary to provide for the required investment in infrastructure to allow the Corporation to continue to provide safe and reliable service, and are essential to preserve the financial integrity of the Corporation in order to promote rate stability for customers.

Even with the proposed and indicative rate increases projected in MH14, retained earnings from electric operations are projected to fall from $2.7 billion in 2014/15 to $2.0 billion by 2023/24. This amount is barely sufficient to absorb the impact of the reoccurrence of a historic 5-year drought, and does not provide sufficient reserves to mitigate the potential financial impacts of the considerable array of risks the Corporation faces in fulfilling its mandate.

Manitoba Hydro's equity ratio for electric operations is projected to deteriorate from the current level of 23% to 10% by 2022/23 as a result of the increase in carrying costs and levels of debt associated with the extensive investment in infrastructure, combined with the reduction of revenues primarily as a result of increased DSM savings.

With the proposed and indicative 3.95% rate increases, Manitoba Hydro's interest coverage ratio is also forecast to be well below target for several years of the forecast. In six years of the 10 year forecast, Manitoba Hydro's interest coverage ratio is projected to be below 1.0, which indicates that the utility would experience elevated operational liquidity risk and may have difficulty generating sufficient revenues and cash flow from operations to pay its interest obligations.

Similarly, the capital coverage ratio is below target for several years as a result of lower net earnings and the increase in capital requirements for the renewal and replacement of aging infrastructure. Manitoba Hydro has historically funded sustaining capital expenditures through internally generated funds; however, it is projecting capital coverage ratios below 1.0 in six years of the 10 year forecast, which indicates that the utility will not generate sufficient revenues to fund its sustaining capital expenditures and must borrow in order to renew or replace existing infrastructure.

The following figures demonstrate the significance of the projected rate increases by comparing the net income, retained earnings, and financial ratios of electric operations including and excluding the proposed and indicative rate increases. As can be readily seen in the following figures the rate increases are vital to the continued financial strength of Manitoba Hydro.

Figure 2.19: Projected Net Income (2015-2024)

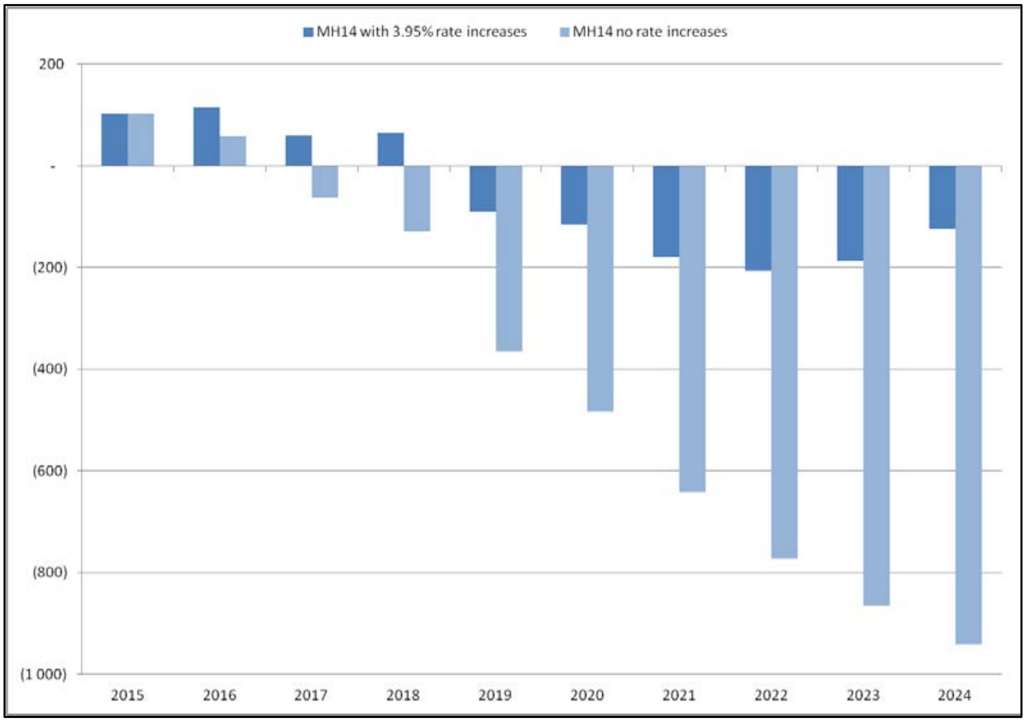


Figure 2.20: Projected Retained Earnings (2015-2024)

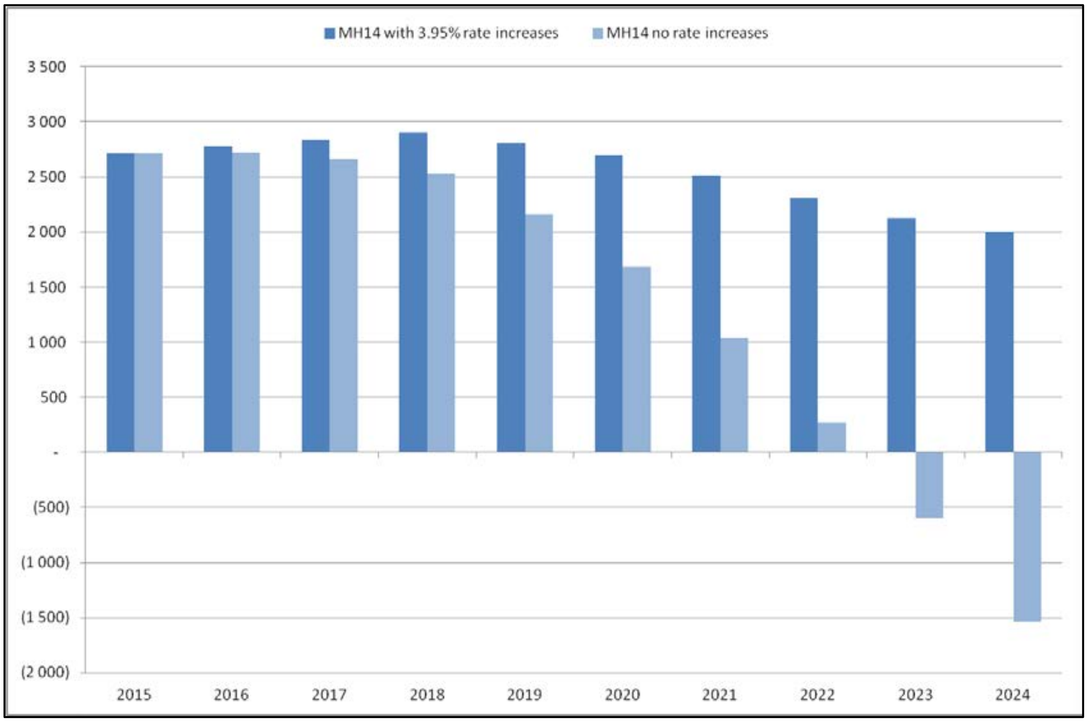


Figure 2.21: Projected Equity Ratio (2015-2024)

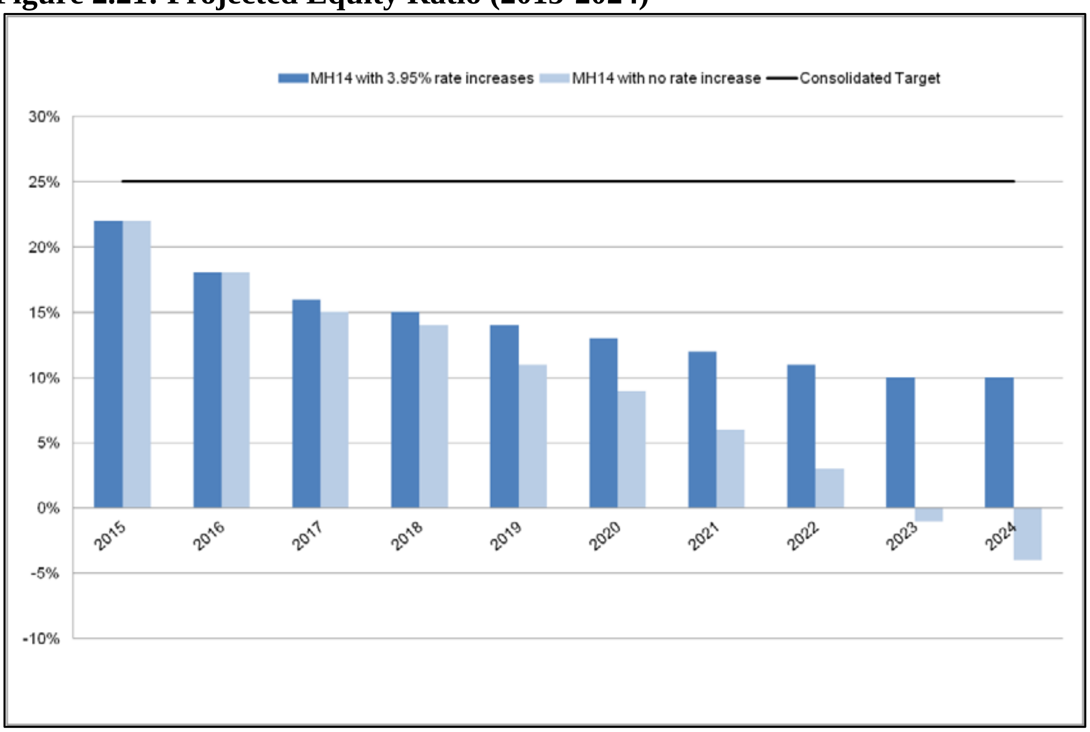


Figure 2.22: Projected Interest Coverage Ratio (2015-2024)

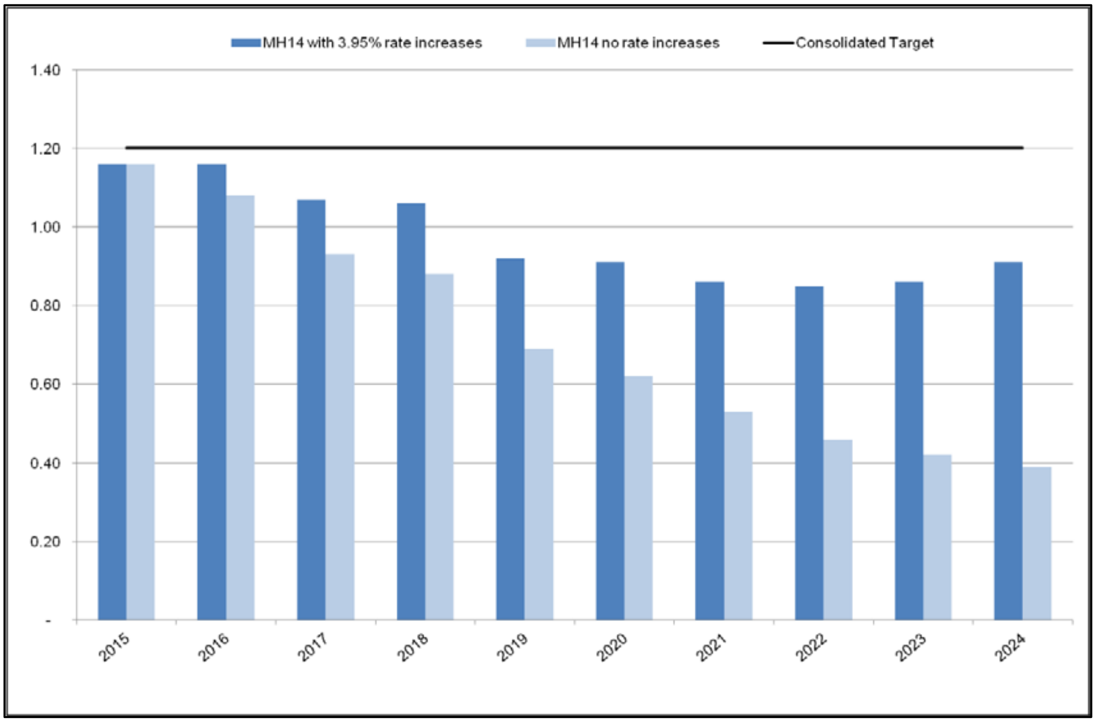
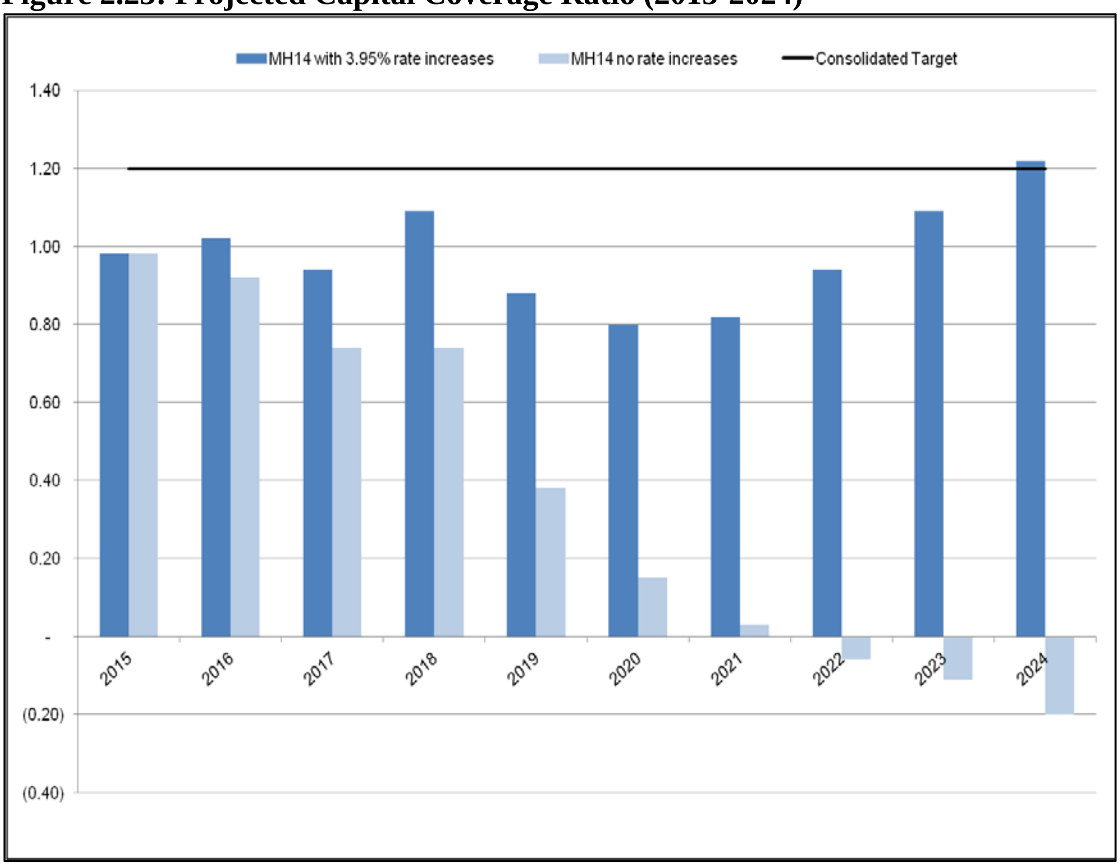


Figure 2.23: Projected Capital Coverage Ratio (2015-2024)

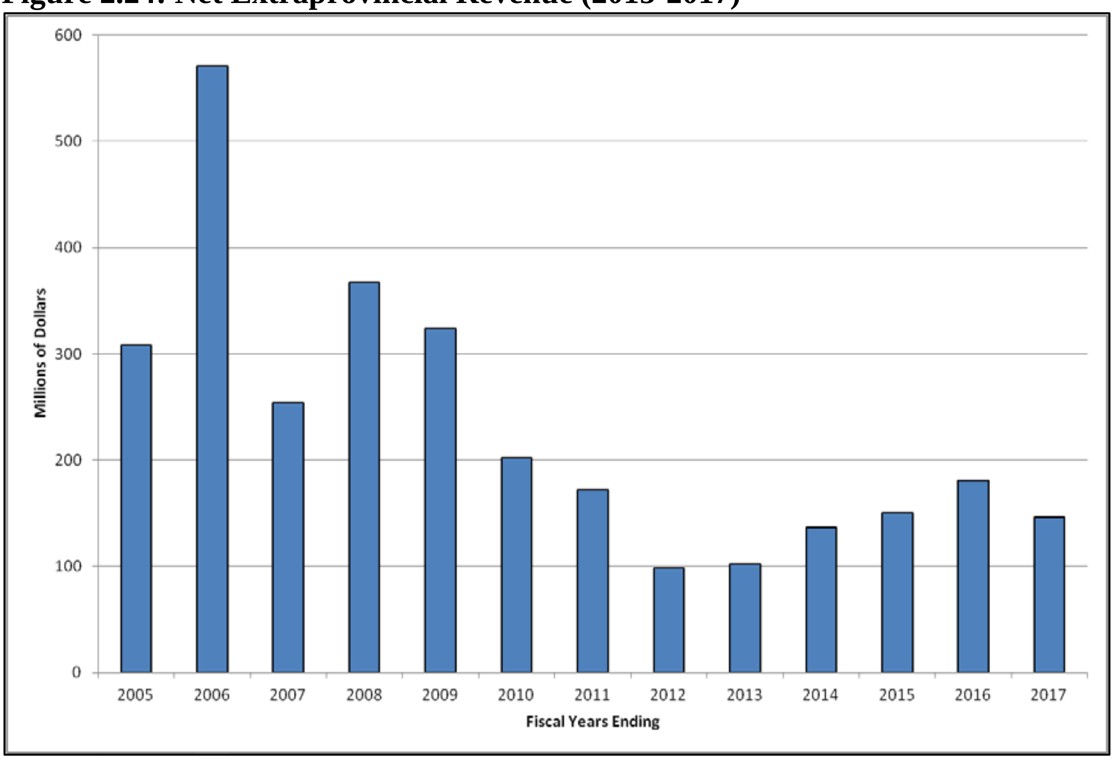


2.3.5 Rates Have Not Increased to Fully Compensate for Reductions in Net Extraprovincial Revenue

Historically, net extraprovincial revenues have made a significant contribution to overall revenues which has enabled Manitoba Hydro to maintain lower electricity rates for Manitobans.

As illustrated in Figure 2.24, net extraprovincial revenues have not been as strong as in previous years. Manitoba Hydro's net extraprovincial revenues are projected to be $150 million in 2014/15, $181 million in 2015/16 and $147 million in 2016/17, which is significantly lower than the average net extraprovincial revenues generated from 2004/05 to 2008/09 of approximately $365 million per year. It is necessary to gradually increase rates over time to compensate for the reduction in net extraprovincial revenues.

Figure 2.24: Net Extraprovincial Revenue (2015-2017)



*Actuals 2004/05 to 2013/14; forecast 2014/15 to 2016/17

2.3.6 Manitoba Hydro's 2015/16 & 2016/17 Rate Proposals Maintain Net Income and Financial Ratios at Acceptable Levels

Approval of the proposed rate increases in this Application are required to maintain net income and financial ratios for 2015/16 and 2016/17 at acceptable levels, and are necessary to promote rate stability for customers and ensure the financial integrity of the Corporation.

Figure 2.25 below summarizes the actual electric operations net income for the past two fiscal years and the projected net income for 2014/15, 2015/16, and 2016/17 from MH14.

Figure 2.25: Net Income from Electric Operations

Net Income - Electricity Operations

			Forecast		
(in millions of $)	**2013**	**2014**	**2015**	**2016**	**2017**
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 437	$ 1 454	$ 1 460
- Bipole III Reserve	-	(19)	(30)	(32)	(34)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 572	1 617	1 587
Expenses	1 407	1 439	1 495	1 571	1 653
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	510	548
Depreciation and Amortization	392	411	405	401	422
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before proposed rate increases	$ 78	$ 147	$ 102	$ 58	$ (58)
Proposed rate increases (3.95% April 1, 2015 and 3.95% April 1, 2016)				57	118
Net Income including proposed rate increases	$ 78	$ 147	$ 102	$ 115	$ 59

Retained Earnings and Financial Ratios (without proposed rate increases)

Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 721	$ 2 663
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.08	0.93
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	0.92	0.74

Retained Earnings and Financial Ratios (including proposed rate increases)

Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 778	$ 2 837
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.16	1.07
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	1.02	0.94

The proposed interim rate increase of 3.95% effective April 1, 2015 is expected to generate additional revenue of $57 million in 2015/16. With this increase, the forecast net income from Electric operations for 2015/16 is projected to be $115 million; the equity ratio is projected to be 18%; and the interest coverage and capital coverage ratios are projected at 1.16 and 1.02 respectively.

Absent the proposed rate increase for 2015/16, Manitoba Hydro is projecting net income of $58 million from Electric operations; the equity ratio is projected to be 18%; and the interest coverage and capital coverage ratios are projected to deteriorate to 1.08 and 0.92 respectively. Furthermore, without the proposed rate increase for 2015/16, Manitoba Hydro is projecting net income of only $2 million in 2016/17 even if it obtained a 3.95% increase effective on April 1, 2016. In this scenario, projected retained earnings are forecast to be $57 million and $115 million lower in 2015/16 and 2016/17 respectively.

The proposed rate increase of 3.95% effective April 1, 2016 is expected to generate additional revenue of $60 million in 2016/17. With this increase, the forecast net income from Electric operations is $59 million; the equity ratio is projected to be 16%; and, the capital coverage and interest coverage ratios are projected to be 1.07 and 0.94 respectively.

Without the proposed rate increase for 2016/17, Manitoba Hydro is projecting a net loss of $58 million; the equity ratio is projected to decline to 15%; and the interest coverage and capital coverage ratios are projected to further deteriorate to 0.93 and 0.74 respectively (well below the 1.20 target levels).

Considering the financial outlook as projected in MH14, there is financial justification for requesting rate increases in excess of 3.95%. Higher rate increases in the order of 5.5% to 6.0% for the next four years would be necessary to reduce the losses that are projected in the next 10 year period and maintain financial reserves at current levels. This would reduce the risk of the need for larger rate increases in the event of a significant drought or other adverse financial conditions.

Despite these risks, Manitoba Hydro has maintained the minimum proposed rate increases at the 3.95% level in consideration of customer sensitivity to rate increases.

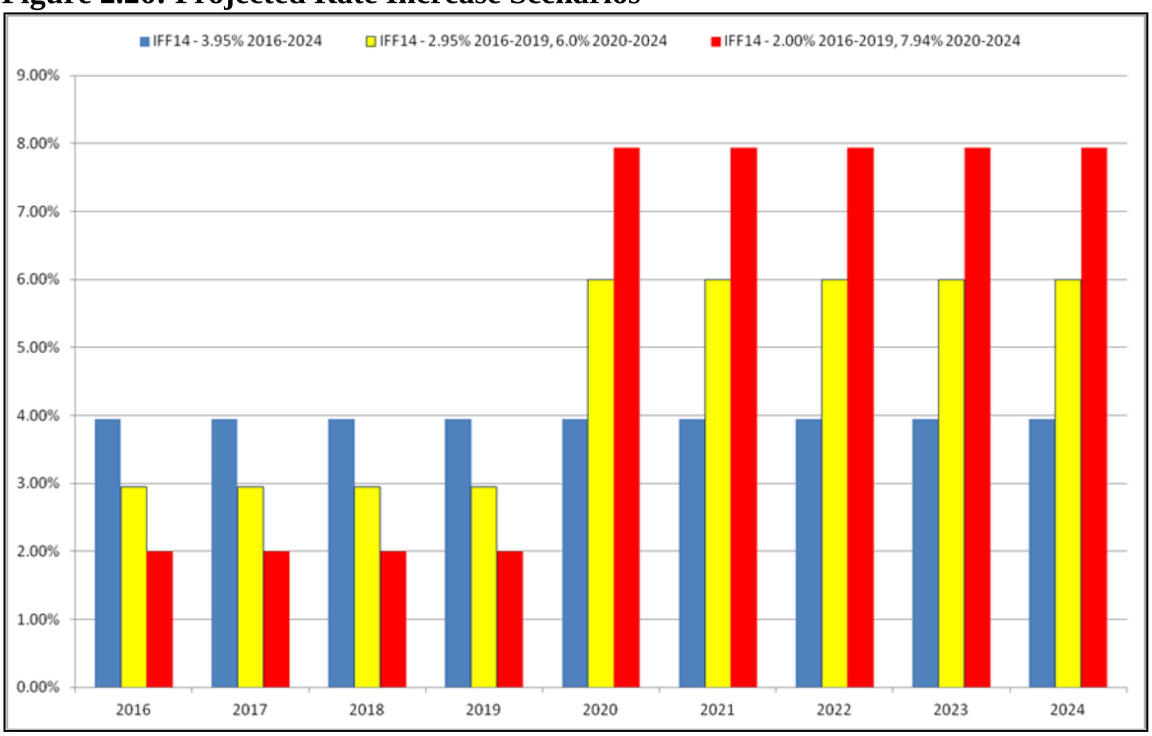
2.4 RISKS IF PROPOSED RATE INCREASES ARE NOT GRANTED

2.4.1 Increased Risk to Customers of Rate Instability and Rate Shock

To demonstrate the potential rate volatility of reducing the near term 3.95% indicative rate increases in MH14, Manitoba Hydro has prepared two scenarios that calculate the compensating rate increases that are required in the five year period from 2020 to 2024 if rate increases for the four year period from 2016 to 2019 were reduced to 2.95% or 2.0%, respectively.

The following figure demonstrates that with 2% rate increases for the next 4 years, Manitoba Hydro would require 8% rate increases for the following five years, and with 2.95% rate increases for the next four years, Manitoba Hydro would require 6% rate increases in the five years that follow. This analysis demonstrates how future rate increases would have to significantly increase in order to compensate for lower rate increases obtained in the near term.

Figure 2.26: Projected Rate Increase Scenarios



Given that these rate scenarios are also derived using average water flow assumptions and that adverse drought conditions may occur in the future, it is of vital importance that the rate increases be regular and occur even when there are short-term favorable water flow or financial conditions. In Manitoba Hydro's view, gradually raising rates by the minimum 3.95% rate increases is in the customer's best interest as this maintains customer rate stability and predictability, and reduces the risk of severe rate shock in the future.

2.4.2 Increased Risk to Customers of Decrease in Service & Reliability

A considerable portion of Manitoba Hydro's assets were installed when many of the first generating stations and transmissions lines were built (1911-1950) and a large portion of the province was electrified (1940-1960), and subsequently when generating stations and supporting HVDC systems were developed in Northern Manitoba (1960-1990). Historically, the reliability performance of Manitoba Hydro's electric assets has been excellent, and ratepayers in Manitoba have enjoyed the benefits of an affordable supply of safe and reliable electricity for many decades. However, many of Manitoba Hydro's generation, transmission and distribution assets have reached an age where their overall condition is such that system reliability has begun to degrade.

As shown in the following figures, Manitoba Hydro's reliability performance based on the SAIFI and SAIDI indicators show an increased trend of outage frequency and duration. Likewise, generation forced outage rates have increased significantly in the past four years.

Figure 2.27: Manitoba Hydro SAIDI and SAIFI Indictors

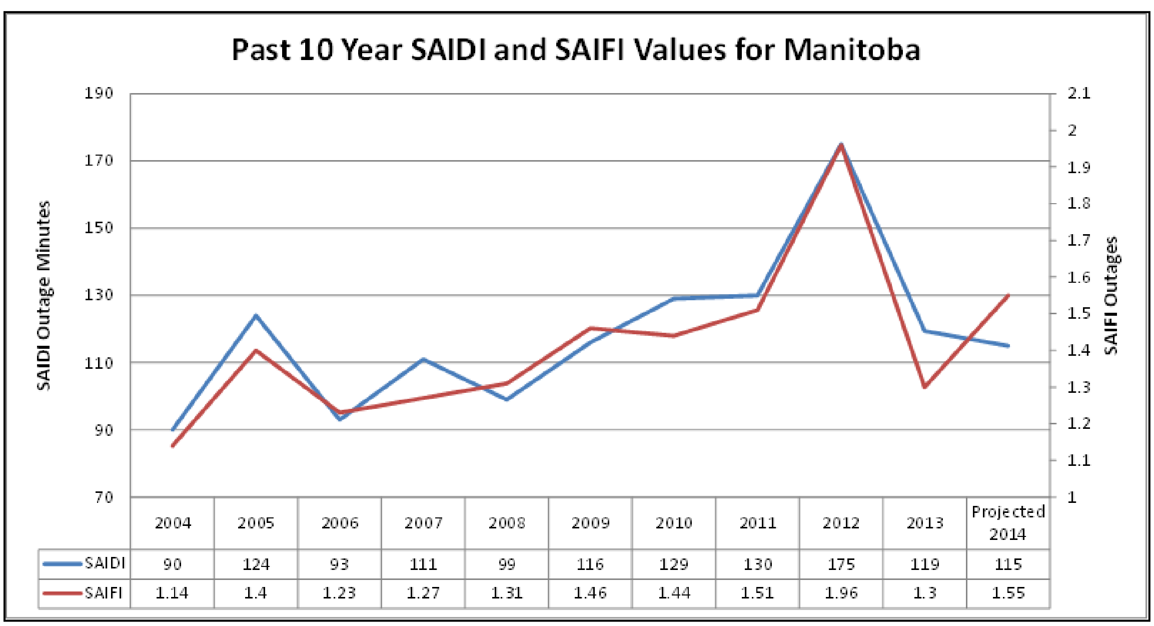
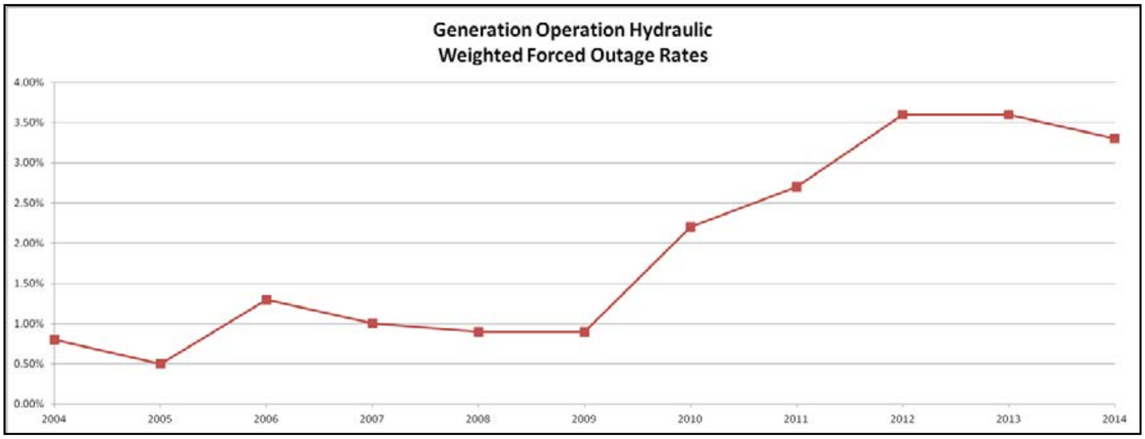
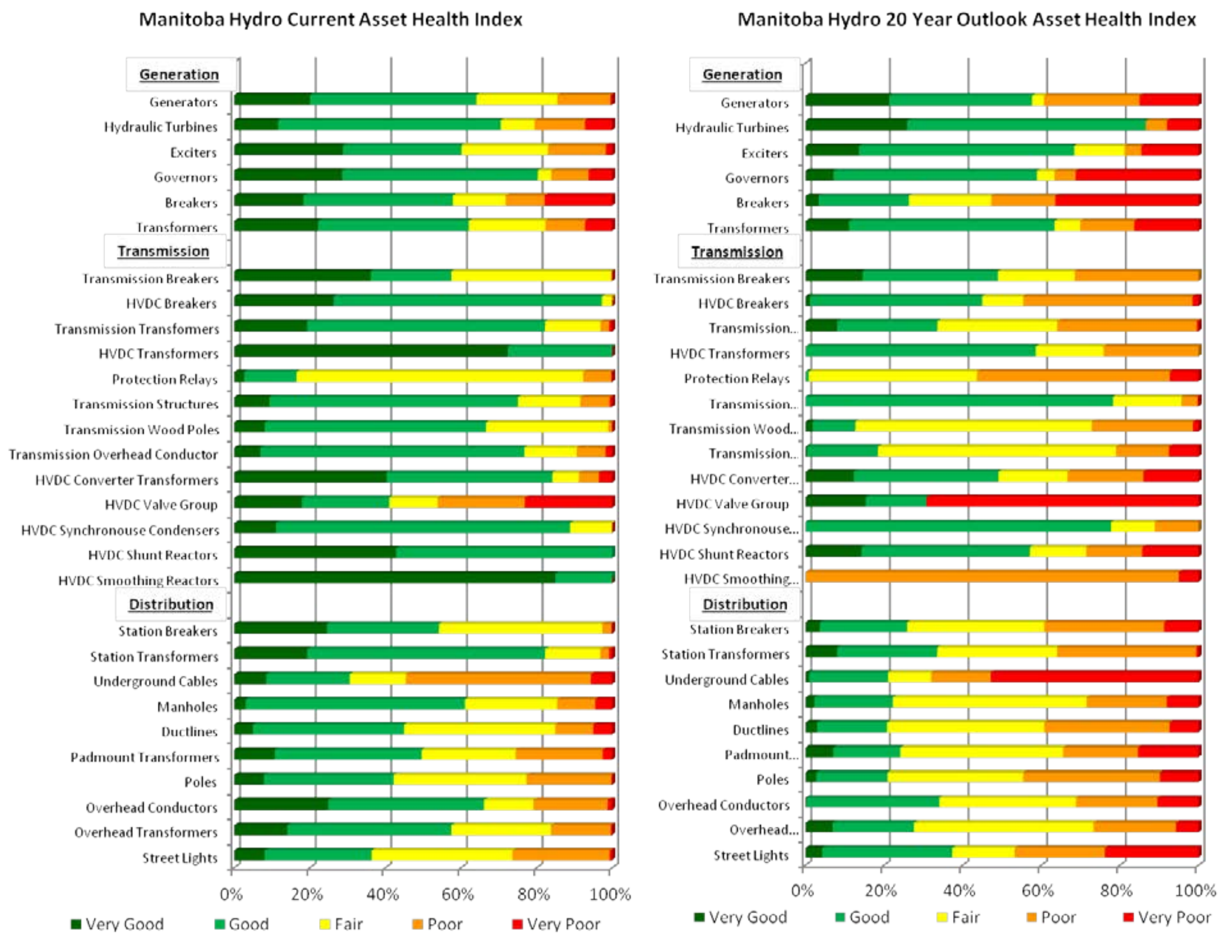


Figure 2.28: Hydraulic Generation Forced Outage Rates



Manitoba Hydro uses an Asset Health Index ("AHI") to quantify equipment condition based on numerous parameters, to indicate whether the asset type is in very poor, poor, fair, good or very good condition. The figures below provide a summary of current AHI results for Manitoba Hydro's generation, transmission and distribution asset types, as well as the 20 year outlook of the AHI based on current asset replacement rates.

Figure 2.29: Asset Health Indices- Current & 20 Year Outlook



As a larger percentage of assets age beyond life expectancy, they will begin to fall into the poor and very poor categories and system failures and customer outages are expected to occur on a more regular basis. As such, replacement rates in the majority of Manitoba Hydro's asset types need to be increased to better align with life expectancy.

The rate increases proposed in the Application are the minimum required to fund the necessary capital investment to replace Manitoba Hydro's aging infrastructure. The following summarizes some of the major risks that would be associated with inadequate funding of sustaining capital:

- Reliability would degrade further, outages would become longer and more frequent;
- Extraprovincial revenues would be lost as a result of additional generation equipment failures;

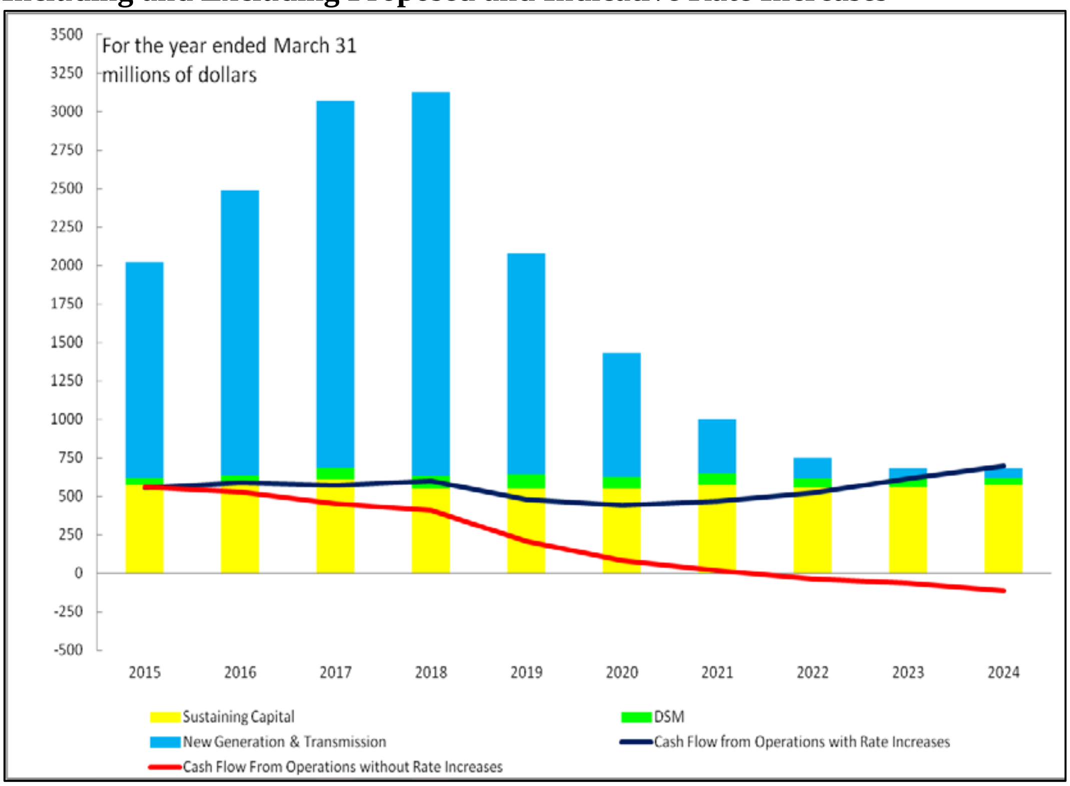
- Timeframes for repair/replacement would be impacted by insufficient lead times;
- Increased safety risks to public and staff;
- Maintenance and emergency costs would increase; and,
- Backlog of requirements would overwhelm the capability of resources to respond.

With the proposed rate increases, Manitoba Hydro will be in an improved position to fund the necessary investments in order to continue to provide the high level of safe and reliable service to which customers are accustomed.

2.4.3 Increased Borrowing Requirements Result in Higher Levels of Debt and Carrying Costs, which will Ultimately Need to be Recovered from Customers

As can be seen in the following figure, without the proposed and indicative rate increases, Manitoba Hydro would be required to fund a continually increasing portion of its sustaining capital expenditures through debt financing as opposed to through the cash flow generated from operations.

Figure 2.30: Electricity Capital Expenditures and Cash Flow from Operations Including and Excluding Proposed and Indicative Rate Increases



Maintaining reasonable financial ratios through regular and reasonable rate increases is in the best interests of customers as it reduces the need for borrowing and additional financing costs that must be borne by customers, which serves to reduce the pressure on future rates and provide more financing flexibility in the event of adverse financial circumstances.

It is important that Manitoba Hydro be granted the proposed rate increases to be able to generate sufficient cash flow from operations to finance sustaining capital expenditures. This will allow Manitoba Hydro to maintain reliable service to customers in a sustainable manner.

2.4.4 Potential Negative Implications to the Provincial Credit Rating and Manitoba Hydro's Borrowing Costs

The Province of Manitoba has a high credit rating as can be seen in the following figure that shows the long term credit ratings for each of the Canadian provinces. As Manitoba Hydro receives a flow through credit from the Province of Manitoba, this high credit rating benefits its customers by reducing the cost of borrowing that the Corporation must recover in its rates.

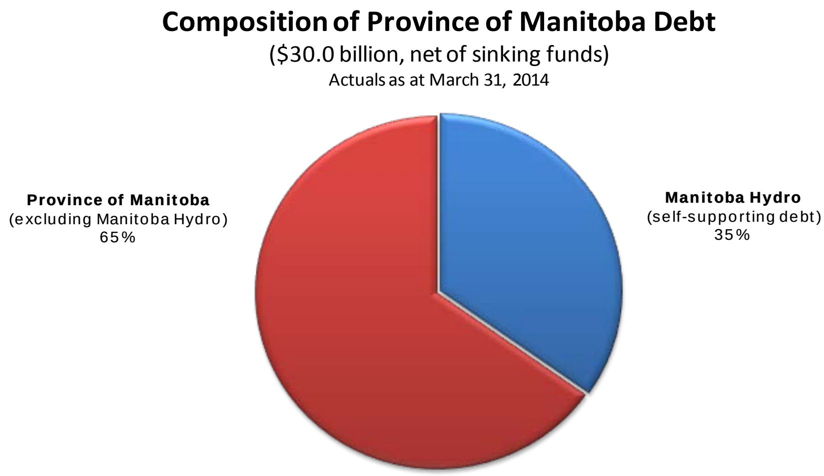
Chart 2.31: Provincial Long Term Credit Ratings Comparison

Province	Standard & Poors	DBRS	Moody's Investors Service
British Columbia	AAA	AA (high)	Aaa
Saskatchewan	AAA	AA	Aaa
Alberta	AAA	AAA	Aaa
Manitoba	AA	A (high)	Aa1
Ontario	AA-	AA (low)	Aa2
Nova Scotia	A+	A (high)	Aa2
Newfoundland & Labrador	A+	A	Aa2
Québec	A+	A (high)	Aa2
New Brunswick	A+	A (high)	Aa2
Prince Edward Island	A	A (low)	Aa2

Rating reports are issued to individual provinces and not necessarily at the same time.

As demonstrated in Figure 3.32, debt advances to Manitoba Hydro form a significant portion of the total provincial debt and the Corporation's financial performance is therefore a contributing factor toward the financial strength and stability of the Province's credit rating. The Credit Rating Agencies view Manitoba Hydro to be financially self-supporting in that the Corporation is able to meet its financial obligations based on its own revenues without being supported by the tax-base of the Province.

Figure 2.32: Composition of Province of Manitoba Debt



Credit rating agencies view Manitoba Hydro's current low rates and reasonable regulatory framework as positive ratings considerations. It is important that credit rating agencies continue to view Manitoba Hydro's debt as self-supporting and that weakened financial ratios as a result of major capital investments and reinvestments do not negatively impact the credit ratings of the Province or Manitoba Hydro's borrowing costs.

The proposed rate increases are necessary to continue to demonstrate to the credit rating agencies that the regulatory framework in Manitoba is supportive of Manitoba Hydro's self-supporting financial status.

2.5 AREAS OF CONCERN RAISED IN PREVIOUS PROCEEDINGS

In the 2012/13 & 2013/14 GRA and Interim Application for Rates Effective April 1, 2014, there were a number of concerns expressed that Manitoba Hydro would like to address in this section of the Application.

2.5.1 Rate Increases are Required Notwithstanding More Favourable Near-term Financial Results

In past proceedings, it has been suggested that in years where the current financial results are favourable, lower rate increases would be sufficient to maintain the short-term financial position of the Corporation.

Manitoba Hydro's MH14 is forecast based on expected water flows for the first year of the forecast (2014/15), median water flows for the second year of the forecast (2015/16), and the average revenues for all water flow conditions for the past 102 years for the subsequent years of the forecast (2016/17 and thereafter).

In the near term, to 2016/17, projected net income from electric operations (including the proposed rate increases) is higher in MH14 as compared to MH13, largely due to favourable water flow conditions, as well as lower finance and depreciation expense. Although inflow conditions are currently favourable and Manitoba Hydro has confidence that these conditions will persist until the end of March 2015, water inflow conditions in fiscal 2015/16 are very uncertain and can be quite different from those assumed in MH14. The main factor that determines water supply conditions in 2015/16 is precipitation, which is highly variable and unknown at this time. MH14 assumes median water inflows in 2015/16 which means that there is an equal probability that water inflows will be higher or lower.

Notwithstanding the more favourable near-term results, there are lower net earnings projected in the remaining years of MH14, such that between the period 2017/18 to 2023/24 projected net earnings from electric operations (including indicative rate increases of 3.95% per year) are $666 million lower compared to MH13.

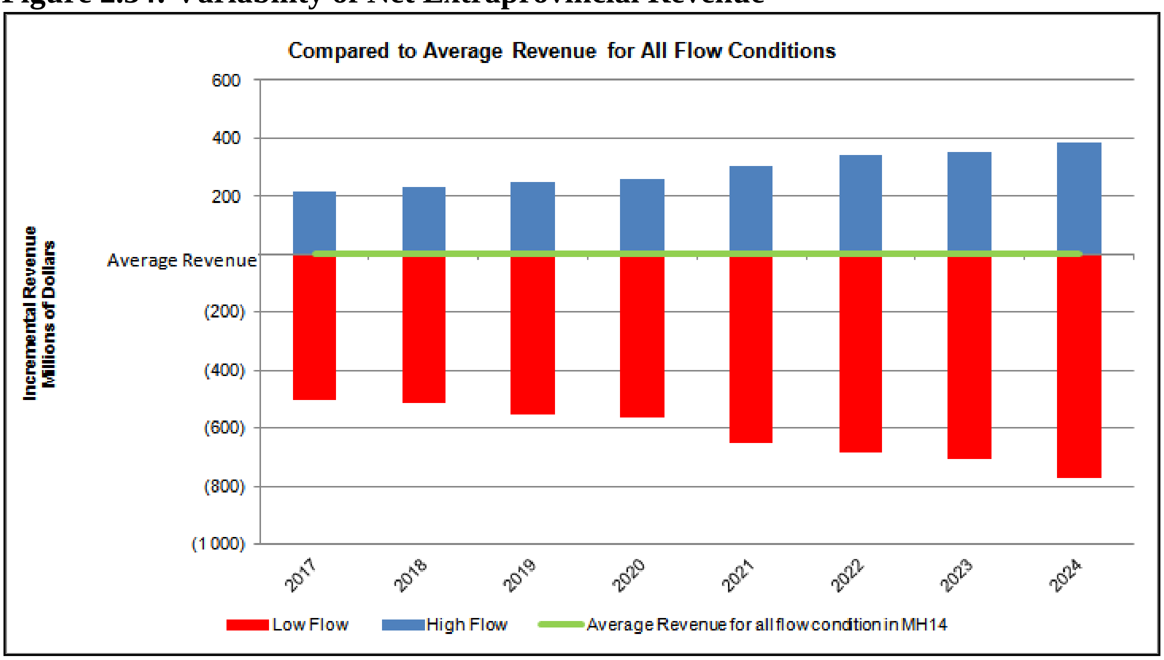
In total, MH14 projects net losses of $901 million between 2018/19 and 2023/24. As a result, financial reserves are projected to deteriorate from the current level of $2.7 billion to $2.0 billion by 2023/24.

Figure 2.33: Comparison of Electric Operations Net Income MH14 to MH13

	Forecast 2014/15	Forecast 2015/16	Forecast 2016/17	10 Year Cumulative to 2023/24	20 Year Cumulative to 2033/34
Current Forecast (MH14)	$ 102	$ 115	$ 59	$ (559)	$ 3 003
Previous Forecast (MH13)	55	12	19	(85)	4 775
Increase/ Decrease	$ 48	$ 103	$ 41	$ (474)	$ (1 772)

It is also important to recognize that Manitoba Hydro's financial results are subject to significant volatility based on potential changes in water flow conditions. This is demonstrated by the following chart which compares the potential increase in net extraprovincial revenues as a result of high water flows (blue bars) with the potential decrease in net extraprovincial revenues associated with low water conditions (red bars) for the period from 2016/17 to 2023/24. In this chart, the bolded green line represents the average revenues for all flow conditions upon which the extraprovincial revenues in MH14 have been forecast.

Figure 2.34: Variability of Net Extraprovincial Revenue



The 3.95% indicative rate increases are derived based on the assumption of average revenues for all water flows. Actual water flows and the associated financial impacts will deviate either up or down from the assumption of average. Over time, the financial impacts resulting from low and high water flows will balance out. In order to maintain

the indicative even annual rate increases over the long-term, it is necessary that rate increases be implemented gradually even in years with favourable water flows and financial results. The law of averages dictates that implementing lower rate increases in reaction to years with favourable water conditions, will result in the need for higher rate increases in years with lower water conditions in order to balance out with average revenue requirements over the longer term. This approach does not contribute to rate stability for customers.

As a result of the extensive investments that Manitoba Hydro has to make to continue to provide safe and reliable service to customers, there is a requirement for a period of continual rate increases to cover the associated costs. Setting rates considering longer-term revenue requirements, as opposed to being overly focused on the shorter term financial outlook, is the prudent approach and in the best interest of customers. Focusing only on the short term, will inevitability result in rate instability as ratepayers will be faced with substantially higher rate increases in the future, especially considering the longer term and significant investments Manitoba Hydro is undertaking.

The Corporation believes that the position advanced by the Green Action Centre (page 3 of its written submission) as part of Manitoba Hydro's Application for Interim Electric Rates effective April 1, 2014 appropriately acknowledges that the proposed rate increases should be assessed through a longer-term perspective.

> *"In order to reconcile the variability of the Manitoba Hydro revenue stream with the stability desired by many of Manitoba Hydro's customers, the Board ought to look at setting rates on the basis of longer term trends as opposed to the actual results of last year's revenues or the short-term conditions, be they favourable or unfavourable. GAC is of the view that the current longer term trends point strongly in the direction of requiring more revenue for Manitoba Hydro"*

While reducing rate increases in the short-term may offer some temporary relief to ratepayers in the immediate year, the reality is that doing so does not eliminate the impact on consumers but only defers the rate increase to a future period. Regular and moderate rate increases, such as those proposed in this Application, minimize the impact to ratepayers arising from the unavoidable need to make the necessary investments in Manitoba Hydro's system and the risk associated with adverse conditions such as below average water flow conditions. Such an approach is critical when considering the long term significant investments that Manitoba Hydro is undertaking on behalf of customers.

If Manitoba Hydro has short-term results that are more favourable than forecast, the situation is actually beneficial for customers as the Corporation would be required to borrow less debt, which would ultimately reduce the costs to be recovered from ratepayers. The forecast net income for the three-year period is not unreasonable when one considers the size of Manitoba Hydro's asset base, and that the implied return on equity would be less than 2-3%, well below the return requirements if Manitoba Hydro was a privately owned utility.

To ensure rate stability for customers, Manitoba Hydro submits that the most reasonable and prudent approach is to implement regular and reasonable rate increases, even during periods of favourable water flows, thereby balancing the inevitable years of less favourable than forecast results where water flows are below average.

2.5.2 Inflationary Rate Increases are Not Sufficient to Maintain Rate Stability for Customers

In past proceedings, it has been suggested that Manitoba Hydro's rate increases be limited to inflationary adjustments, in or around 2% per year, in order to maintain Manitoba Hydro's short-term financial position.

As an example of the risk to customers of allowing only 2% rate increases in the short-term, the following charts demonstrate the impacts to net income, retained earnings, and financial ratios of continual 2% rate increases for the period from 2016 to 2024, as compared to the proposed and indicative rate increases of 3.95%.

Figure 2.35: Projected Net Income (2015-2024)

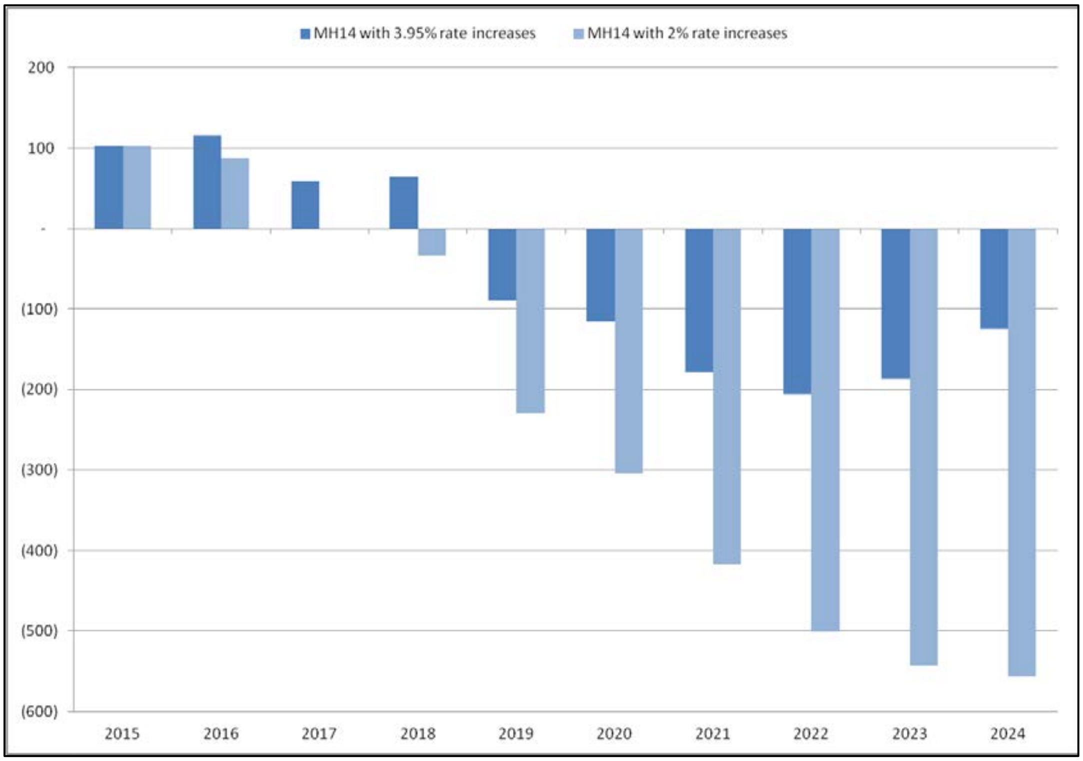


Figure 2.36: Projected Retained Earnings (2015-2024)

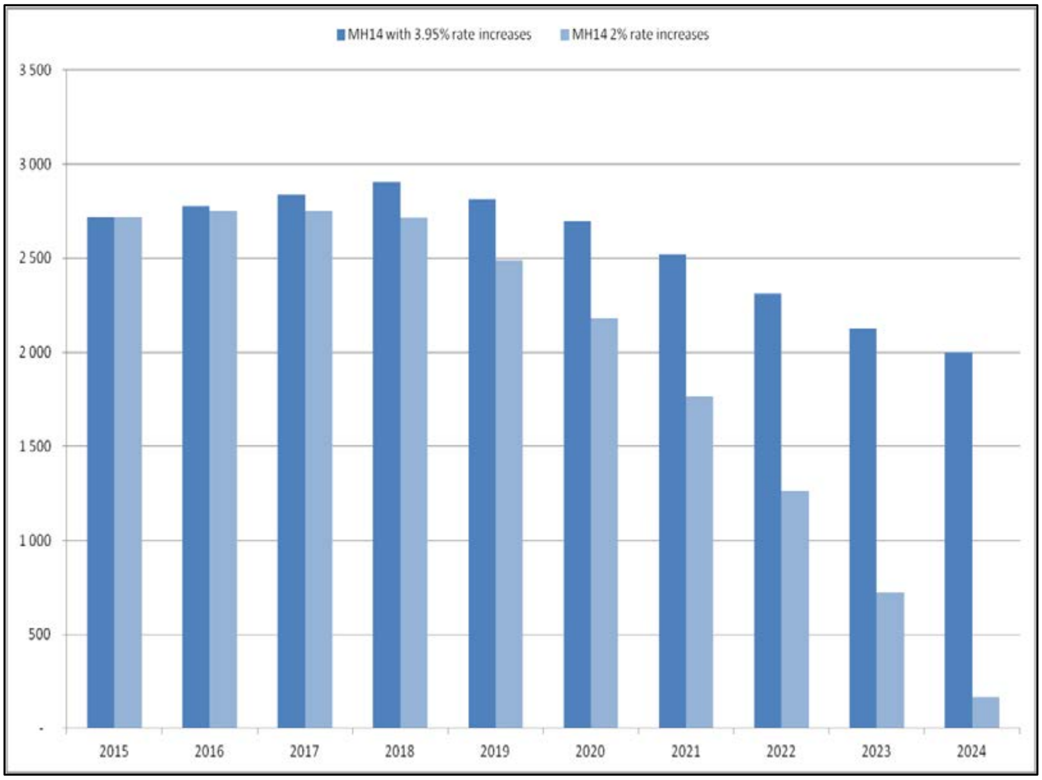


Figure 2.37: Projected Equity Ratio (2015-2024)

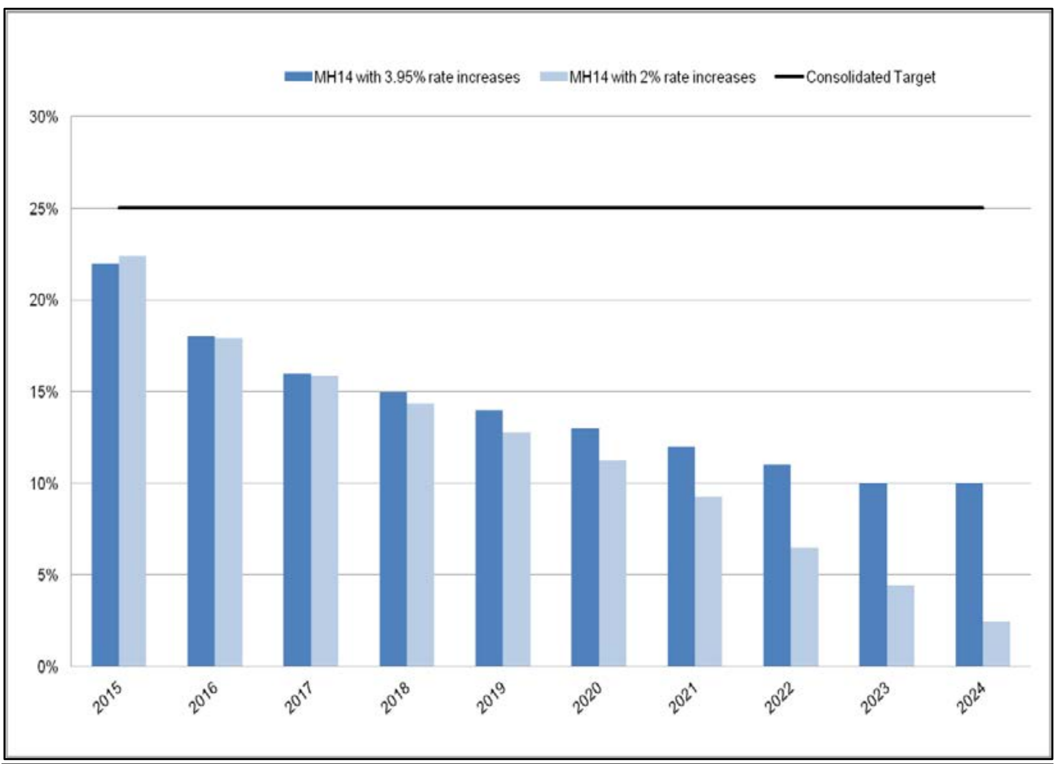


Figure 2.38: Projected Interest Coverage Ratio (2015-2024)

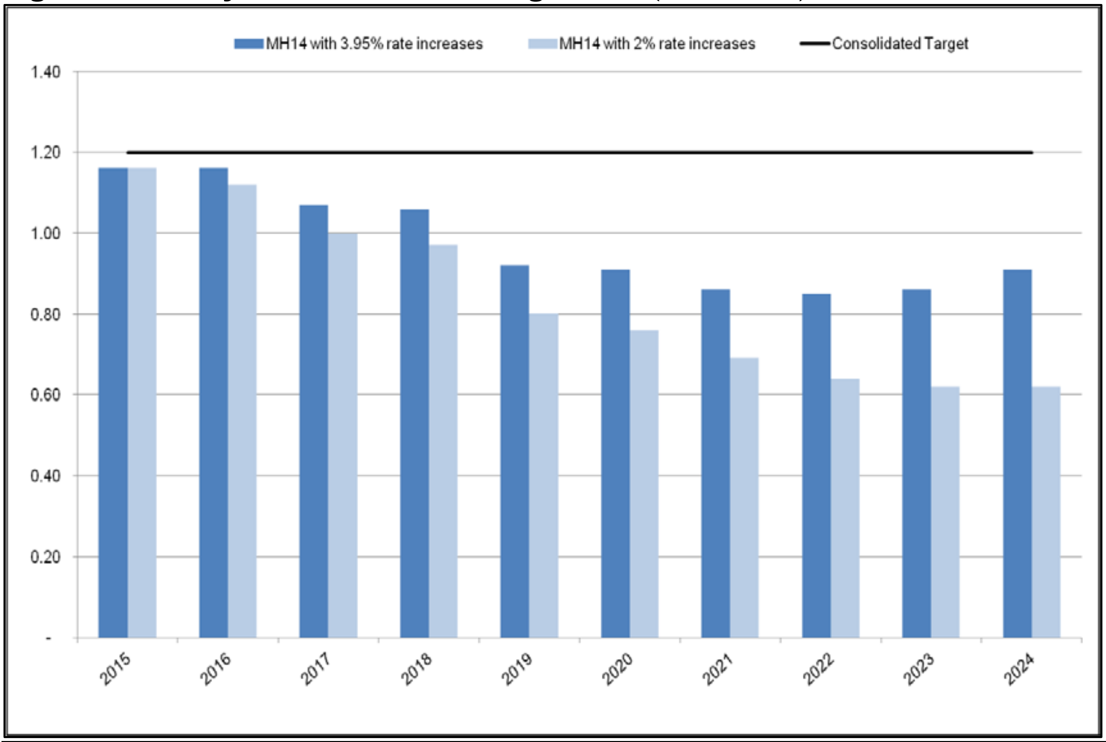
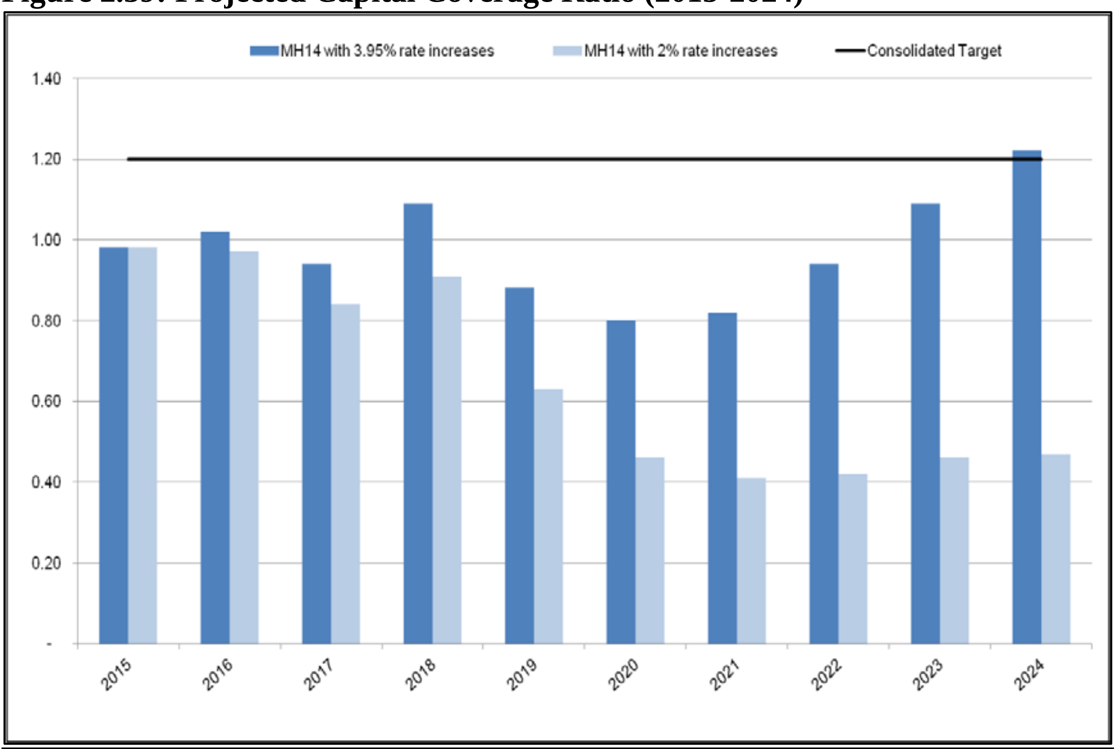


Figure 2.39: Projected Capital Coverage Ratio (2015-2024)



The projected increases in Manitoba Hydro's revenue requirement are being largely driven by the extensive investments to be made on behalf of domestic customers, which are much more significant than inflationary cost pressures.

A rate increase that is based upon inflation jeopardizes Manitoba Hydro's ability to provide rate stability to customers as it will be unable to recover its costs of providing an essential service and ensure sufficient financial reserves are in place. Similar to the suggestion that a rate increase can be forgone during those years where current results are better than projected, granting a rate increase that does not allow the utility to recover its costs each year will only result in higher borrowing requirements in future. The impact of deferring or reducing the needed 3.95% rate increases will be to the detriment of customers, as it serves to increase the requirements for higher rate increases in the future than have been projected in MH14. This approach does not achieve rate stability in the long-run and will subject consumers to increased rate volatility in the future.

2.5.3 Manitoba Hydro is Effectively Controlling its Costs to Maintain Projected 3.95% Rate Increases

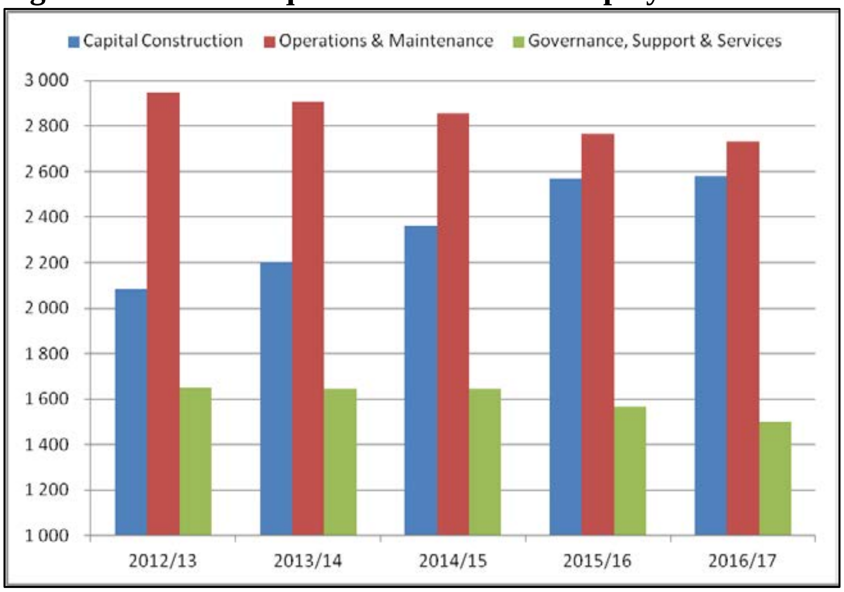
In past proceedings, concerns have been expressed about Manitoba Hydro's efforts to contain its operating costs.

Manitoba Hydro is committed to carefully managing its costs and utilizing resources efficiently and effectively to fulfill its mandate and provide maximum value to its stakeholders and ratepayers. In order to fulfill this commitment, Manitoba Hydro continues to develop measures to manage its operating costs, while at the same time balancing the need to ensure staffing levels are adequate to provide safe and reliable service.

Manitoba Hydro's most significant cost in providing service to customers is wages and benefits. Manitoba Hydro has undertaken an extensive review of its staff complement and is committed to reducing approximately 300 operational positions over the 3 year forecast period from 2014/15 to 2016/17. These reductions will be achieved through attrition through the application of technology, and the consolidation and elimination of work processes where appropriate.

The following figure provides a summary of the Corporation's actual and projected Equivalent Full Time ("EFT") employees for the period 2012/13 to 2016/17 segregated between those EFTs that work on capital construction, operations & maintenance, and provide governance & support services. As should be expected during a period of significant capital investment the EFTs associated with capital construction are increasing. In contrast, consistent with Manitoba Hydro's commitment to manage its operating costs, the number of EFTs associated with operations & maintenance and governance & support activities are forecast to decline.

Figure 2.40: Total Equivalent Full Time Employees



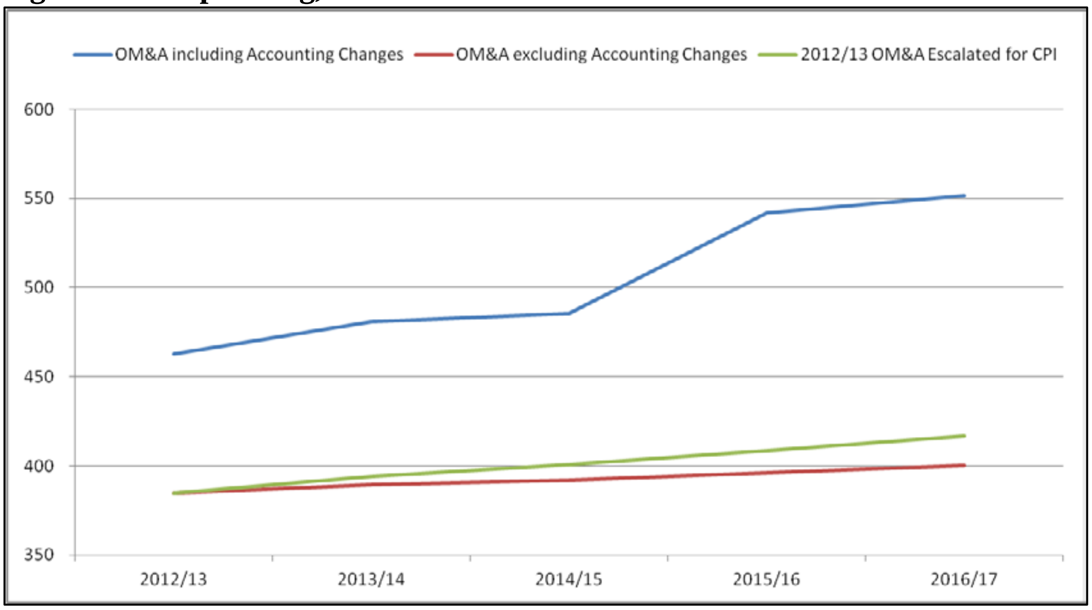
Manitoba Hydro is continually undertaking a number of initiatives across the various Business Units that are intended to result in further operating and capital cost savings. Some of these key initiatives include:

- Consolidation of Rural District Offices
- Implementation of Mobile Workforce Management
- Review of the Gillam Redevelopment & Expansion Project
- Supply Chain Management Initiatives

As shown in the following figure, these measures will allow the Corporation to maintain Operating, Maintenance & Administrative cost increases at an annual average increase of 1% per year (excluding accounting changes that impact OM&A) through fiscal 2016/17 and beyond, which is below inflationary levels. These cost containment measures have assisted the Corporation in maintaining projected annual rate increases at the same 3.95% level as those projected in MH13, despite the Corporation facing significant and increasing cost pressures. This is consistent with the expectations of the PUB in Order

43/13, wherein it recommended that Manitoba Hydro control OM&A costs increases below inflation.

Figure 2.41: Operating, Maintenance & Administrative Costs



2.5.4 Proposed Rate Increases are Not Being Driven by Aggressive Accounting Policy Selection

In past rate proceedings, concerns have been expressed that Manitoba Hydro's rate increases are being driven by aggressive accounting policy choices, in particular the expensing of additional overheads and the proposed change to the depreciation methodology.

In Order 43/13, the PUB accepted the accounting policy changes that have been made by Manitoba Hydro to 2013/14 for the purposes of rate setting but indicated that until an IFRS Status Update Report is filed at the next GRA, no further changes should be made for rate-setting purposes.

As is outlined in further detail in this Application, there are a number of prospective accounting changes that Manitoba Hydro is making for financial reporting purposes in 2014/15 and 2015/16. The most significant of these include the implementation of a comprehensive depreciation study in 2014/15 and further changes to the level of capitalized overhead and deprecation methodologies as part of the implementation of IFRS in 2015/16.

As summarized in Figure 2.42, these changes offset each other and result in an overall reduction in Manitoba Hydro's future revenue requirements. The significance of the net changes are minimal in the 2015 to 2017 period, and are clearly not driving the need for future rate increases during this timeframe.

Figure 2.42: Accounting Policy & Estimate Changes

Accounting Policy & Estimate Changes Electric operations (in millions of $s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OM&A Expense Changes		51	56	57	58	58	59	60	61	62
Depreciation Expense Changes	(25)	(53)	(57)	(60)	(76)	(86)	(96)	(101)	(103)	(105)
Other		(3)	(3)	(4)	(3)	(3)	(4)	(4)	(3)	(4)
Total Increase (Decrease) in Revenue Requirement	(25)	(4)	(4)	(7)	(22)	(31)	(41)	(45)	(46)	(48)

Given that the net impact of these changes are not driving the need for rate increases and not harming ratepayers, it is the position of Manitoba Hydro that IFRS financial reporting policies should be adopted for rate-setting purposes.

Furthermore, as has been the position of Manitoba Hydro in previous rate proceedings, under the cost of service rate-making approach that has been utilized by Manitoba Hydro, it is unnecessary and undesirable to maintain two sets of financial records, one for financial reporting purposes and one for rate-setting purposes. To have two sets of financial records could cause confusion for Manitoba Hydro's various stakeholders, including the PUB as they would be using different sets of financial information to make important decisions with respect to the Corporation's operations and finances.

2.5.5 Manitoba Hydro is Projecting Deterioration of its Financial Ratios to Mitigate the Rate Increases to Customers

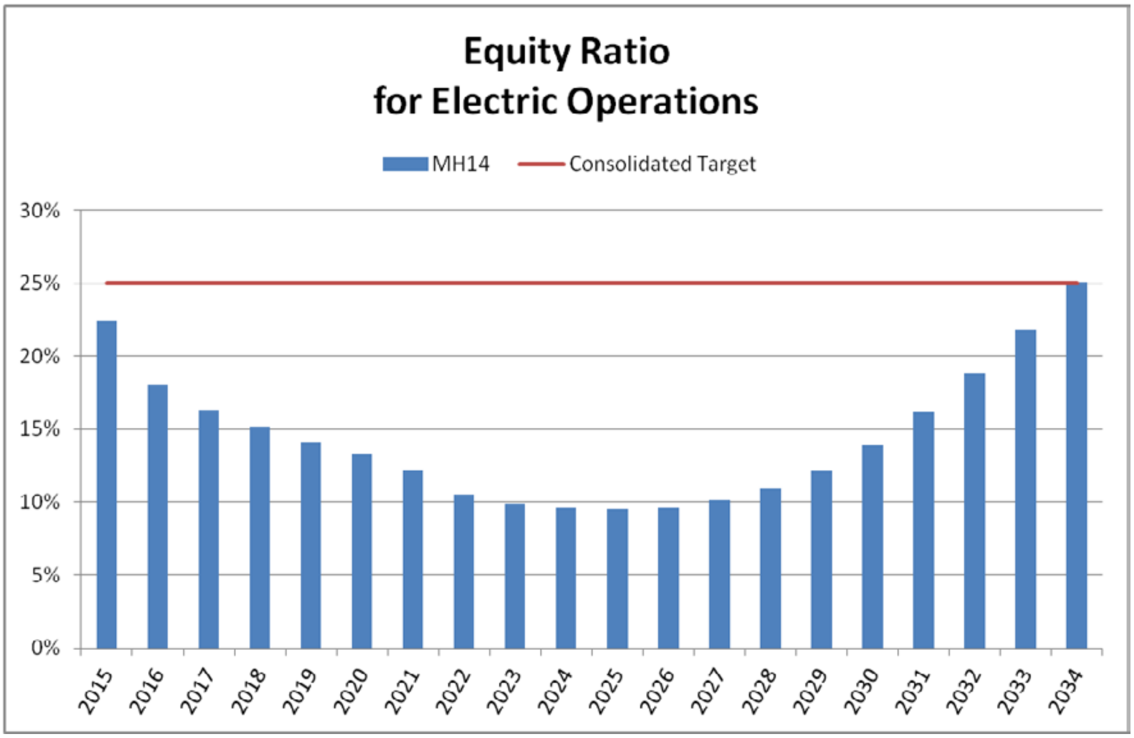
There has been a suggestion that Manitoba Hydro should relax its 75/25 debt-to-equity target to moderate its proposed electricity rate increases.

Manitoba Hydro recognizes that the rate increases that would be necessary to maintain its financial ratios at or above targets in the near to medium term, would be financially challenging for its customers. Further, this would be inconsistent with Manitoba Hydro's approach of smoothing rate increases over time in order to promote rate stability. Consequently in MH14, financial results and ratios are projected to be significantly below target for an extended period of time. Notwithstanding Manitoba Hydro's desire to smooth rate increases to customers over time, the Corporation recognizes that the 3.95%

rate increases are the minimum that are required to maintain rate stability and financial integrity.

As demonstrated in the following figure, even with the 3.95% rate increases Manitoba Hydro's electric operations equity ratio is expected to deteriorate to 10% by 2022/23, and not recover to the 25% target until 2033/34.

Figure 2.43: Equity Ratio for Electric Operations MH14



Manitoba Hydro's interest coverage and capital coverage ratios are also well below targets for an extended period of time and only recover within the later years of the 20 year forecast period. The retained earnings with respect to electric operations are projected to decrease to $1.9 billion by 2024/25, which is barely sufficient to absorb the impact of the reoccurrence of the historic 5-year drought, and does not provide sufficient reserves to mitigate the potential financial impacts of the considerable array of the risks the Corporation faces in fulfilling its mandate.

Relaxing the longer-term financial targets will not negate the need for the requested rate increases, as the 3.95% proposed and indicative rate increases are the minimum necessary to manage the significant deterioration in Manitoba Hydro's projected financial results and ratios in the next 10 year period.

2.5.6 It is Appropriate to Set Rates for 2016/17 as Part of the Current Rate Proceeding

In Order 49/14, the PUB indicated that it would be reluctant to approve rates for 2016/17 as Manitoba Hydro is undergoing a period of significant and fairly rapid change.

Manitoba Hydro acknowledges that it is embarking on a period of unprecedented capital expenditures to meet the energy needs of Manitobans. While there have been a number of regulatory proceedings in the past where Manitoba Hydro's major capital plans have been discussed at length, the Corporation has now received the necessary approvals and has commenced construction on the Bipole III Reliability Project in the winter of 2013, and the Keeyask Generating Station in the summer of 2014. As well, the Corporation has completed a more comprehensive assessment of the condition of its assets and the capital requirements associated with the renewal of its existing asset base, and is pursuing an enhanced Power Smart program with a significantly higher level of investment. As such, there is now more certainty with respect to Manitoba Hydro's investment requirements than there has been in the recent past.

In this environment, it is the view of Manitoba Hydro that it is most appropriate to begin to address the rate-setting and revenue requirement matters associated with these investments on a proactive basis, rather than to defer their consideration solely to future rate proceedings. Accordingly, Manitoba Hydro submits that the examination of the 2016/17 rate increase during this proceeding is both appropriate and desirable.

Manitoba Hydro also notes that, in the normal course, it seeks approval of rates for two forward looking test years based on the Corporation's most up to date financial forecast. Accordingly, the filing of a GRA early in 2015 would normally address two future test years (2015/16 and 2016/17).

If Manitoba Hydro were to proceed with a GRA for the 2014/15 and 2015/16 test years only at this time, the financial requirements are such that it would be necessary to file a subsequent GRA later in 2015, which would include the 2016/17 test year. Such an Application would follow only a few months after the conclusion of the proceeding for the current GRA and would necessitate the need for Manitoba Hydro to request another interim rate increase in order to implement new rates effective April 1, 2016. In Manitoba Hydro's view, deferring the consideration of the 2016/17 rate change to a future regulatory proceeding is not in the best interest of customers as it exposes them to another interim rate increase for 2016/17 and does not promote regulatory efficiency.

2.6 THE PROPOSED RATE INCREASES ARE ESSENTIAL TO PROVIDE CUSTOMER VALUE

Manitoba Hydro takes great pride in providing Manitobans with reliable service and some of the lowest electricity rates in North America. This has been accomplished through careful management of its assets, prudent spending on capital projects and by managing its operating and administrative costs.

Manitoba Hydro is now entering a period of extensive investment and re-investment in its infrastructure. This investment is needed for three main purposes: 1) to meet the growing energy needs of Manitoba families and businesses, 2) to replace aging generation, transmission and distribution assets that are approaching the end of their service lives, and 3) to address capacity issues on the existing system. Manitoba Hydro is committed to using revenues prudently for these purposes and demonstrating that its actions are cost effective, efficient and fiscally responsible.

The revenues from the proposed rate increases are necessary so that Manitoba Hydro can deliver on its mandate by:

- Continuing to deliver a reliable energy supply to Manitobans by funding the necessary investments to respond to the need for system growth and asset replacement;
- Funding Power Smart programs to assist customers in meeting their energy needs in a cost effective manner;
- Continuing to provide rates that are affordable for Manitoba families and that support the competitiveness of Manitoba business;
- Ensuring rate stability and predictability for customers by maintaining its financial strength; and,
- Equitably serving the needs of all Manitoba residents, regardless of where they live in the province—urban or rural, remote or central, north or south.

Manitoba Hydro conducts its business operations in an environmentally, socially, and fiscally responsible manner, and with the revenues from the proposed rate increases can continue to provide customers with reliable service and stable rates into the future.

Corporate Strategic Plan

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This photo, courtesy of Lawrence Janzen (Dorsey/Riel converter stations) shows the Riel terminal station on September 19, 2013 during commissioning of the bay and structure lights in the 230-kilovolt north yard. The Riel Reliability Improvement Initiative is key to Manitoba Hydro's commitment in maintaining a reliable supply of electricity.

Manitoba Hydro

Message from the President & CEO

Manitoba Hydro's Corporate Strategic Plan (CSP) is the primary tool for the Executive Committee and Manitoba Hydro-Electric Board to establish, communicate and drive corporate priorities and strategy within the organization. The CSP is dynamic and designed to reflect the evolving nature of the energy industry within which Manitoba Hydro operates. It will be updated and re-published every three years unless changes to the strategic direction prompt a need for an earlier revision.

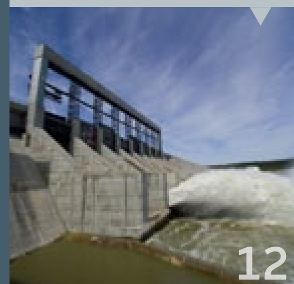
Most people flip a switch or turn up the thermostat without much thought as to where the energy behind it comes from. In the past year we have initiated a discussion with customers to consider what lies behind the switch. To provide a reliable supply of electricity and natural gas to meet the current and future energy needs of the province we must invest to renew, upgrade and construct new infrastructure.

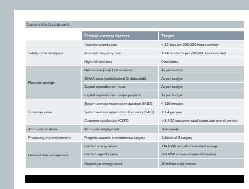
Our plan continues the proven strategy of developing this province's clean, renewable hydro resources and building interconnections to leverage the associated export sale opportunities while enhancing reliability. To meet the province's energy needs, the most economic options are pursued which continue to include aggressively pursuing demand side options. We are investing in a powerful future for Manitoba, ensuring the next generation will continue to enjoy the benefits of affordable, reliable and sustainable electricity when they need it.

As a Crown Corporation, Manitoba Hydro is committed to being an outstanding corporate citizen. We aspire to create positive relationships with our customers, employees and all stakeholders. The Corporation works closely with economic development agencies to attract new business, encourage expansion of existing businesses and to retain existing customers. Through purchasing, investments and job creation, Manitoba Hydro is a significant contributor to economic development in communities province-wide.

I am proud of our company and its achievements. I know the future promises to be an exciting and challenging one. I'm confident that our employees will continue to do what they've always done – take personal responsibility for their own contributions and embrace these new challenges head on.

Scott A. Thomson, CA
President & CEO





Vision

To be recognized as a leading utility in North America with respect to safety, reliability, rates, customer satisfaction and environmental leadership.

Mission

To provide for the continuance of a supply of energy to meet the needs of the province and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy.

Operating principles

Work together for the success of the organization as a whole, recognizing that all our activities are interrelated.

Establish long-term cooperative relationships with all employees, customers, suppliers and other stakeholders, aimed at achieving our shared Vision.

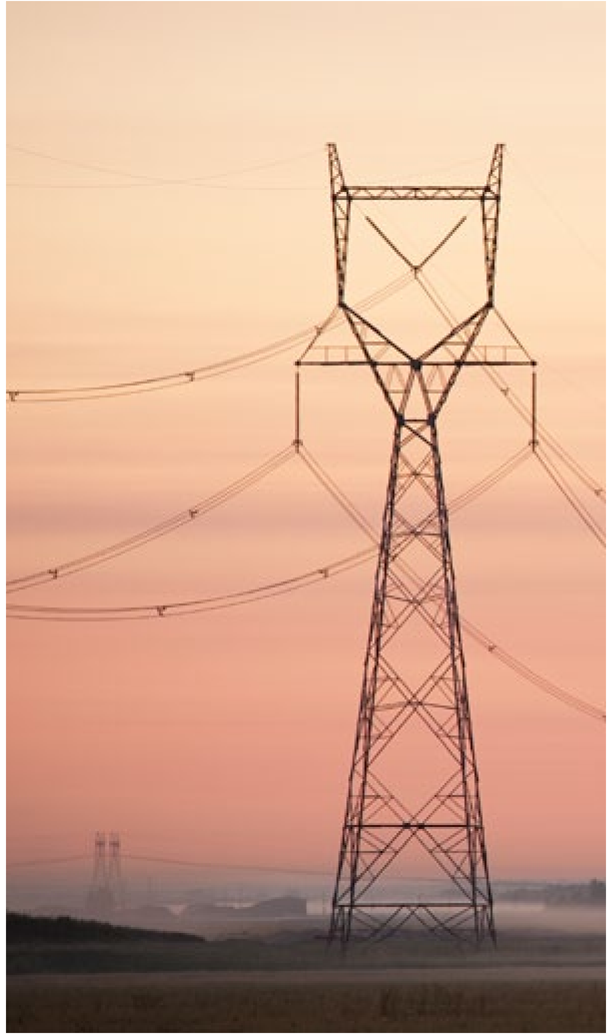
Create a working environment that removes barriers to effective performance and which fosters mutual respect, trust and open communication.

Promote a safety-focused culture in which all employees support and demonstrate safe work behaviors.

Provide opportunities for all employees to develop their full potential, recognizing people's inherent desire to do their best.

Measure outcomes, develop an understanding of the causes of variation from planned performance and take appropriate action.

Drive continuous improvement by identifying opportunities to streamline processes and improving efficiencies across the organization as a whole.



Above: 500-kilovolt tower at sunrise near Winnipeg's north Perimeter Highway and Highway 7.

Electricity

The Manitoba demand for electricity is continuing to grow and new energy sources are required. This is a direct result of Manitoba's continued economic growth through:

- Increases in population and related services;
- Higher average energy usage per residential customer;
- Continued Manitoba industrial and commercial customer expansion.

To meet this increased demand, Manitoba Hydro's plan continues to include aggressively pursuing demand side options and developing clean, renewable hydro resources. It also includes new transmission interconnection and distribution infrastructure to deliver power to Manitoba customers with enhanced access to export markets.

The plan includes:

- Power Smart* energy conservation programs (> 800 MW in planned cumulative capacity savings);
- Keeyask generation, 695 MW;
- Conawapa generation, 1 485 MW;
- Transmission associated with Keeyask and Conawapa;
- Investment in a significant portion of existing infrastructure to renew and upgrade the electric system to improve the reliability of supply.
- Additional transmission import/ export capacity to Minnesota and Wisconsin;
- New major export sales.

Manitoba Hydro is a licensee of the Trademark and Official Mark.

Left: One of three transformers moving through the streets of Winnipeg to the Riel station in Springfield. They were installed as part of Manitoba Hydro's reliability improvements on its 500-kilovolt line linking Manitoba and Minnesota.

Electricity (continued from page 4)

This plan, relative to alternative options:

- Results in the overall highest net benefits to Manitoba Hydro and lowest long-term domestic rates for Manitobans;
- Supports Manitoba Hydro's long-term fiscal health;

Above: About 96 per cent of the electricity Manitoba produces each year – 30 billion kilowatt-hours on average – is clean, renewable power generated at 15 hydroelectric generating stations on the Nelson, Winnipeg, Saskatchewan, Burntwood and Laurie rivers.

- Protects customer service by providing the highest level of system reliability and energy security;
- Supports risk management and flexibility to respond to changing conditions such as higher or lower load growth, uncertainty in level of future demand side management (DSM), changes in river flows due to climate change and additional export market opportunities;
- Provides the highest financial benefit and offers the highest socio-economic benefits (including employment and provincial economic growth) to Manitobans;
- Provides the most beneficial package of socio-economic impacts and benefits to northern and aboriginal communities through training, employment, business opportunities, income sharing and participation in environmental and socio-economic protection;
- Capitalizes on Manitoba's valuable endowment of renewable hydropower rather than imported non-renewable resources;
- Supports Manitoba's Clean Energy Strategy and sustainable development principles by providing clean renewable energy and a legacy for future generations.

The plan incorporates different pathways to allow for future flexibility in adjusting the plan based on changing conditions. A pathway consists of:

- A choice to embark upon an initial development plan today;
- A sequence of decision points that will occur in the future as information modifies or eliminates current uncertainties, such as price forecasts for natural gas and exports and approvals of new interconnections;
- Examples of alternative plans or changes to the initial plan that can be chosen to respond to emerging realities.

A pathway represents the initial decision to commit to one development plan at the outset but not an obligation to rigidly see that plan through regardless of circumstances. Load growth, Power Smart plans, export contracts, natural gas price forecasts, export price forecasts, greenhouse gas restrictions, capital cost estimates, interest rates and other parameters will be continually monitored and reviewed.

Decisions for future power generation and transmission and distribution system development will depend on the best information available at that time. If circumstances warrant, the plan will be modified at key decision points.

Natural gas

From a provincial perspective, the demand for natural gas in Manitoba is forecast to be relatively flat over the next ten years (from 2013) despite expected annual increases in the province's population. Increases in natural gas demand due to population growth are mainly offset by the energy savings achieved through investments in newer energy efficiency technologies and a trend of reduced use of natural gas water heating systems. However, some geographic areas within Manitoba are experiencing accelerated growth in natural gas demand where pipeline capacity and infrastructure must now be increased.

Natural gas plays a significant role in meeting Manitoba's energy needs – the demand for natural gas currently served by Manitoba Hydro's gas distribution system is the equivalent of approximately 1.4 times the size of the total hydro-electric generating system if expressed in equivalent energy terms.

During the next few years, Manitoba Hydro will be devoting a significant amount of effort in response to major changes in the North American supply and transportation markets driven by the challenges faced by TransCanada Pipelines and by recent regulatory orders by the National Energy Board. For the past decade, Canada's dominant inter-provincial pipeline has experienced growing economic challenges as a result of declining gas shipments; this has led to dramatically escalating tolls to ship natural gas. Changes in geographic gas production and shipment patterns also require changes to gas distribution operations in order to preserve a reliable flow of gas to customers.

Similar to the electric side of the business, the natural gas distribution system is aging. A more rigorous approach to preserve the integrity of our pipeline assets and continued emphasis on public safety amplifies our commitment to develop comprehensive asset replacement programs. Our goal is to address these infrastructure requirements in order to continue to acquire and deliver natural gas to our customers in a safe, reliable and cost effective manner.

Left: Field worker from Gas Apparatus Maintenance and Control operates a valve at the gate station which supplies natural gas to the Selkirk Generating Station.

Natural gas (continued from page 6)

To meet our customers' future demand for natural gas, Manitoba Hydro's plan includes:

- Aggressively pursuing energy efficiency opportunities (> 100 million cubic metres of planned cumulative savings in gas demand);
- Educating customers on fuel choice alternatives as natural gas currently offers customers a more economic alternative in meeting their heating needs and results in economic benefits for Manitoba Hydro, the province and reduces global greenhouse gas emissions;
- Conducting a natural gas asset condition review, developing a long-term capital plan and re-investing in the existing natural gas system to manage capacity constraints and preserve gas system reliability;
- Studying and assessing possible future natural gas storage and transportation alternatives, including the potential to serve Manitoba from nearby production basins in North Dakota should the necessary pipeline infrastructure be developed;
- Monitoring and evaluating the potential for natural gas storage and/or production to be developed within the province.

Above and near left: Upgrading a gas service, including relocating and welding of gas lines by the Gas Distribution Maintenance Department.

Far left: As part of the CentrePort Canada project, installation of approximately three-and-a-half kilometers of 16-inch natural gas transmission pipeline around the new intersection was needed to accommodate the new traffic overpass at Saskatchewan Avenue and the Perimeter Highway.

Trends and factors influencing the North American energy markets

Customer service expectations

As we deliver electricity and natural gas to customers, we recognize that these are simply inputs to necessities such as heat and light. Due to society's increasing dependency on technology, service and reliability expectations of all customers have increased dramatically over the past decade. The level of service provided by the utilities sector will be expected to keep pace with the integration of technology into our daily lives and the need for instant access to information.

Industrial and commercial customers operating in an increasingly competitive global economy expect utilities to meet their needs with respect to service timelines, rates, power quality and reliability. Obtaining energy service in a timely manner at competitive rates is critical to their business models in order to remain strong competitive entities, while providing Manitoba Hydro with important domestic revenue and contributing to the broader Manitoba economy.

Economic factors

The North American economy continues a trend of slow economic growth. The province of Manitoba is growing, both in population and the broader economy. While Power Smart programs have been and will continue to be promoted to reduce customer energy usage, domestic energy demand is expected to grow in all sectors.

Historically low interest rates are beneficial in a period of capital investment and expansion. Financial markets will be continually monitored as Manitoba Hydro takes on new debt to mitigate risk and maintain financial strength. Over the longer term, interest rates are expected to rebound with the growth in the economy.

Above: Extreme and fluctuating weather conditions such as ice storms can cause ice to form on power lines. Crews use a technique called "ice-rolling" to remove the ice from power lines as quickly as possible to prevent equipment breakage and loss of power. Rollers attached to the end of long poles are pulled along the power lines cracking the ice off as they go.

Trends and factors influencing the North American energy markets

Composition of energy supply

The need for new generation in the United States and Canada is expected to be driven by modest load growth and the replacement of a portion of the aging generation fleet. Electricity demand in both Canada and the United States will continue to increase over the resource planning horizon, with the majority of this growth driven by increased residential and commercial consumption.

Energy and environmental considerations and policies are and will continue to be major factors influencing resource choices and market price for electricity. Global interest and attention to environmental issues and the effects of climate change could have profound impact on the energy industry and provide an opportunity for Manitoba Hydro.

Renewable Portfolio Standards (RPS) exist in many states to encourage the development of renewable electricity generation. These policies require a certain proportion of energy served to be delivered from eligible renewable sources. To the extent that these types of programs include Canadian hydropower as an eligible resource, they would provide an additional incentive to buy electricity from Manitoba.

Recent developments in oil and gas extraction technologies have significantly increased the availability of these resources. The growth of shale gas production has resulted in an abundant new United States energy supply source. When combined with the economic slowdown, these factors have changed the long-term outlook for North American domestic natural gas prices and may impact both customer and utility options. While many utilities will choose to develop natural gas generation, they are likely to continue to seek out emission-free alternatives in order to diversify their portfolio of resources, mitigate expected natural gas price uncertainty and volatility, protect against future carbon price liabilities, and improve environmental performance.

Left: The Nelson River featuring Long Spruce Generating Station with Kettle Generating Station in the background.

Operational excellence describes how Manitoba Hydro intends to meet its mandate. Key areas of focus provide clarity around our priorities and ensure that Manitoba Hydro is positioned for success.

Top priorities include:

- Safety
- Financial strength
- Customer value
- Aboriginal relations
- Workforce management
- Protecting the environment
- Demand side management (DSM)

Corporate dashboard

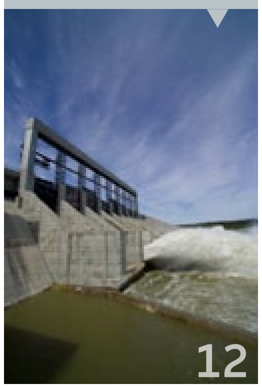
Critical success factors, including corporate targets, are captured in the Corporate dashboard.

Corporate Dashboard

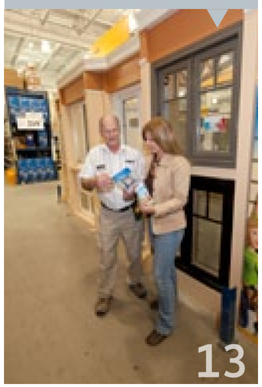
	Critical success factors	Target
Safety in the workplace	Accident severity rate	< 12 days per 200,000 hours worked
	Accident frequency rate	< .60 accidents per 200,000 hours worked
	High risk incidents	0 incidents
Financial strength	Net income (Loss) ($ thousands)	As per budget
	OM&A costs (consolidated) ($ thousands)	As per budget
	Capital expenditures – base	As per budget
	Capital expenditures – major projects	As per budget
Customer value	System average interruption duration (SAIDI)	< 116 minutes
	System average interruption frequency (SAIFI)	< 1.4 per year
	Customer satisfaction (CSTS)	> 8.4/10 customer satisfaction with overall service
Aboriginal relations	Aboriginal employment	16% overall
Protecting the environment	Progress towards environmental targets	Achieve all 3 targets
Demand side management	Electric energy saved	174 GWh annual incremental savings
	Electric capacity saved	201 MW annual incremental savings
	Natural gas energy saved	10 million cubic meters

Safety

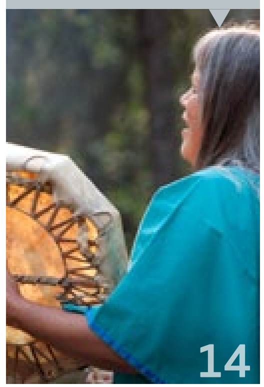
Financial strength



Customer value



Aboriginal relations



Workforce management

Protecting the environment

Demand side management

Safety

Promoting safety in the workplace and in the actions of the public around our facilities remains a top priority and is Manitoba Hydro's most important goal. Manitoba Hydro is committed to continuously improving its safety performance and focusing on strategies to instill a safety and health culture in all corporate activities. In doing so, we intend to maintain a steady decline in both workplace accident severity and frequency rates.

Key areas of focus

- Create a consistent corporate 'Safety First' message targeted at preventing all incidents;
- Reinforce management, supervisory and worker accountability for a safe and healthy workplace;
- Redesign the Safety Training for Leaders program to meet the needs of both informal and formal leaders;
- Integrate risk assessment into all safety-related training programs;
- Provide employees with safety and wellness information and services;
- Mentor all employees to be qualified and well practiced in the use of safe work procedures;
- Deliver effective public education and safety programs to minimize public contacts.

Above: Manitoba Hydro promotes public safety in schools with a range of educational materials and programs.

Left: Job site planning meetings (frequently referred to as a "tailboard" meeting) are meetings held at the job site with all workers involved. They are held before the work begins and as required during the course of the work to ensure that all workers understand the hazards, risks, and procedures associated with the job.

Financial strength

Maintaining financial strength is essential in order to make the necessary investments in infrastructure to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in our operations and to provide customers with long-term rate stability and predictability and avoid the need for large or sudden rate increases in the future. While the required investment in new and existing infrastructure is expected to place a certain degree of pressure on the Corporation's key financial targets, Manitoba Hydro is currently well positioned to make these investments and is committed to carefully managing its costs and balancing the need for reasonable rate increases with sensitivity to customer rate impacts and in doing so, maintain competitive rates for our customers.

Above: The spillway at Kettle Generating Station located on the Nelson River.

Key areas of focus

- Utilize resources efficiently and effectively to fulfill our mandate and provide maximum value to our stakeholders and ratepayers;
- Critically review all capital project proposals to ensure best value;
- Diligently manage capital projects to be on time and on budget, leveraging experience from past projects to improve upon capital cost estimating, and project and contract management;
- Aggressively pursue a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term;
- Fully justify and obtain Public Utilities Board approval for rate increases that will be necessary to achieve financial targets over the long term;
- Closely monitor economic factors, financial markets and energy markets to manage and mitigate financial risk.

Financial targets

The Manitoba Hydro-Electric Board approves financial targets to be considered in all major corporate decisions. These include:

- *Debt: Equity ratio 75:25*
- *Interest coverage ratio > 1.2*
- *Capital coverage ratio > 1.2 excluding major new generation and transmission*

Customer value

Providing excellent customer service, high system reliability* and affordable rates are fundamental in everything we do. We are a leader in promoting conservation, providing numerous Power Smart programs to assist customers in meeting their energy needs.

Key areas of focus

- "Keep the lights on and the gas flowing" with safe and reliable delivery of electricity and natural gas to customers through investment in existing infrastructure and system expansion;
- Assist customers in finding sustainable energy solutions to meet their needs, including fuel choice and energy efficient opportunities and thereby reducing their overall energy bills and impact on the environment;
- Provide predictable, fair and affordable rates for all Manitobans;
- Construct Bipole III to strengthen reliability of the electric system and provide energy security;
- Maintain compliance with applicable North American Electric Reliability Corporation (NERC) reliability standards and foster a culture of reliability excellence.

** Reliability performance is measured as the System Average Interruption Duration (SAIDI) and System Average Interruption Frequency (SAIFI). Our target is to remain in the top quartile when compared to other Canadian Utilities.*

Above: Promoting energy efficient windows.

Left: Downtown Winnipeg at night.

Aboriginal relations

Engaging impacted Aboriginal communities in a positive way is vital to enhance working relationships.

Key areas of focus

- Address the adverse effects of our operations on Aboriginal communities;
- Continue to be a leading Canadian utility in Aboriginal representation through initiatives to recruit, develop and retain Aboriginal employees;
- Develop and maintain business relationships with Aboriginal businesses;
- Foster an appreciation of Aboriginal cultures in the workplace;
- Provide opportunities for Aboriginal participation in future development projects.

Above: A ceremony was held at Wuskwatim Cultural Centre to mark the river diversion.

Left: Gary Spence (Utility Worker) and Mark Sweeny (Manager), both of the Community Relations Department, and both members of the Cross Lake First Nation, conduct a shoreline inspection on Sipiwesk Lake.

Workforce management

Attracting, developing and retaining a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to our success.

Key areas of focus

- Provide employee development programs to enhance employee technical, leadership and business skills;
- Maintain workplace diversity and inclusiveness programs;
- Align workforce planning with corporate priorities;
- Maintain leadership and technical continuity through effective succession planning;
- Promote Manitoba Hydro as an employer* of choice.

** Manitoba Hydro continues to be one of the best places to work in Canada. For the fourth consecutive year, the corporation is part of the Canada's Top 100 Employers list.*

As an employer of choice, Manitoba Hydro has been recognized as having among the best:

- *Physical workplace;*
- *Work atmosphere;*
- *Health, financial and family benefits;*
- *Vacation and time-off;*
- *Employee communications;*
- *Performance management;*
- *Training and skills development;*
- *Community involvement.*

Left: Employees participate in the 8th Habit course on leadership at 360 Portage Avenue.

Protecting the environment

Protecting the environment is an integral part of everything we do. We accomplish this by integrating environmentally responsible practices in all aspects of our business. Environmental protection is carried out with dedication to monitoring programs, climate change initiatives, and environmental research and development.

Key areas of focus

- Maintain and improve Manitoba Hydro's Environmental Management System (EMS) to conform with the ISO 14001 standard;
- Reinforce a culture of environmental awareness and the interaction between the corporation's activities and the environment;
- Participate in the development of evolving environmental regulations and climate change policies;
- Enhance public understanding of how Manitoba Hydro's hydroelectricity exports displace greenhouse gas emissions in other regions;
- Expand green procurement, green fleet and other potential opportunities;
- Plan and implement our projects to avoid or mitigate impacts on the environment;
- Conduct and support environmental research, monitoring and educational programs relevant to sustainable development and Manitoba Hydro's operations.

Above: Collaring caribou as part of the environmental assessment studies for Bipole III transmission line to understand the relationship between caribou, wolves and transmission lines.

Far left: Fall image of frosty plants near Wuskwatim Generating Station.

Near left: Nelson River Sturgeon Board employees from Split Lake First Nation and Thicket Portage collect data in support of research to help increase Manitoba's sturgeon population.

Demand side management

As the province's population and economy continues to grow, demand side management (DSM) plays a key role in meeting Manitoba's future energy needs in a sustainable manner. These efforts assist customers in using energy more efficiently and result in overall lower energy bills.

Key areas of focus

- Develop, implement and promote Power Smart programs that aggressively pursue all economic energy efficiency opportunities for both electric and natural gas customers;
- Capture energy efficiency improvements through the advancement of codes and standards, service extension policies and rate structures;
- Promote the optimum use of electricity, natural gas and alternative renewable energy options in Manitoba;
- Assess customer load displacement options.

What is DSM?

DSM represents the actions taken to influence a customer to modify their pattern of energy usage. DSM focuses on how customers use energy to meet Manitoba's future energy needs. While energy efficiency is the largest component for Manitoba Hydro, DSM is broader in scope and pursues opportunities including:

- *conserving energy;*
- *the timing and level of energy consumption; and*
- *using the appropriate energy source based on the application (gas, electric, or other renewable resource).*

Top: The Brandon University's Healthy Living Centre was constructed to meet Power Smart design standards. The centre features a fitness area, two gymnasiums, a walking track and a sports medicine centre. In the fitness area, several state of the art machines operate only on user-generated energy, not from Manitoba Hydro.

Above: Promotion of commercial Power Smart programs.

Manitoba Hydro corporate dashboard

	Measure	Target
Safety	Accident severity rate	< 12 days per 200,000 hours worked
	Accident frequency rate	< 0.60 accidents per 200,000 hours worked
	Serious incidents	0 incidents
Financial strength	Net income (loss) ($ thousands)	As per budget
	OM&A costs (consolidated) ($ thousands)	As per budget
	Capital expenditures – electric operations – major new generation & transmission ($ thousands)	As per budget
	Capital expenditures – electric & gas operations – major & base capital ($ thousands)	As per budget
Customer value	System average interruption duration (SAIDI)	< 116 minutes
	System average interruption frequency (SAIFI)	< 1.4 per year
	Natural gas system reliability	99.99999964%
	Average unplanned natural gas outage duration	< 4.39 hours
	Number of customers affected by unplanned natural gas outages	< 177 customers
	Customer satisfaction (CSTS – Manitoba Hydro quarterly survey)	> 8.4/10 customer satisfaction
Aboriginal relations	Aboriginal employment	16% overall
Protecting the environment	Progress towards environmental targets*	Achieve all 3 targets
Demand side management	Electric energy saved	363 GWh
	Electric capacity saved	243 MW
	Natural gas energy saved	10 million cubic meters

** Environmental sub-targets:*

a. *Percentage of electricity generated in Manitoba from renewable resources* — *Target: ≥ 99%*
b. *Total annual GHG emissions* — *Target: ≤ 520 kt*
c. *Repeat environmental audit findings* — *Target: 0 repeat findings*

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CORPORATE ORGANIZATIONAL STRUCTURE

Manitoba Hydro’s organizational structure consists of 10 Business Units. A brief description of the role of each Business Unit is provided below. A diagram of Manitoba Hydro’s Organizational structure is provided in Figure 1 of this Appendix.

Corporate Group

The Corporate Group includes the Office of the President & Chief Executive Officer and the Public Affairs Division. The President & Chief Executive Officer leads the Corporation, establishes Corporate policies and practices, and ensures the fulfillment of the Corporation's mandate, mission, and goals. The Public Affairs Division provides specialized communication services geared towards a variety of Corporate-wide projects and issues. The Division produces a wide range of publications for various stakeholders, delivers public open houses, and acts as the official spokespeople for the Corporation.

General Counsel & Corporate Secretary Business Unit

The General Counsel & Corporate Secretary Business Unit provides legal, internal audit, insurance and intellectual property services. The Business Unit consists of the Law Division, the Internal Audit Division, the Insurance Services Department, the Human Rights & Respectful Workplace Advisor, the Compliance Officer and the Intellectual Property Officer.

Corporate Relations Business Unit

The Corporate Relations Business Unit is responsible for building and maintaining relationships with Aboriginal communities, the Provincial government and across Business Units. The Business Unit brings together several planning, analysis, forecasting and coordinating functions to perform corporate level examinations of subjects or issues that are strategically significant to Manitoba Hydro. The Business Unit consists of the Aboriginal Relations Division, the Corporate Planning & Strategic Review Division, and the Government Relations & Current Issues Department.

Finance & Regulatory Business Unit

The Finance & Regulatory Business Unit promotes fiscal responsibility throughout the corporation and provides professional services to other Business Units and external stakeholders. This Business Unit provides a number of services including management and financial accounting, budgeting and financial forecasting, controllership, development of rates and policies, financial market, debt and investment, cash management, and corporate banking services. The Business Unit is also responsible for corporate risk management, recommending and monitoring the Corporation's financial targets, external financial reporting, and supporting and providing policy guidance to other Business Units, and subsidiaries of the Corporation. The Finance & Regulatory Business Unit consists of the Corporate Controller Division, the Rates & Regulatory Affairs Division, the Treasury Division, the Corporate Risk Management Department, the Financial Planning Department and Subsidiary Operations.

Generation Operations Business Unit

Generation Operations provides for the current and future supply of electricity to Manitobans, as well as marketing and selling electricity to export customers in both Canada and the US**.** This Business Unit plans, designs, operates and maintains 15 hydraulic generating stations, 2 thermal generating stations, and a number of water control structures. Generation Operations is also responsible for optimizing the use of its facilities within the interconnected, international electricity market to achieve the lowest reasonable cost to Manitoba electricity customers, while giving due regard to the environment, safety, and reliability. The Business Unit consists of the Engineering Services Division, the Generation North Division, the Generation South Division, the Power Planning Division, and the Power Sales & Operations Division.

Major Capital Projects Business Unit

The Major Capital Projects Business Unit is responsible for managing the licensing, design, procurement, construction, commissioning, and labour relations associated with major projects, including the Keeyask Generating Station, the Bipole III converter stations and transmission line, and the Pointe du Bois spillway reconstruction. The Business Unit consists of the Bipole III Project Division, the New Generation Construction Division, the Licensing & Relationship Management Division, and the Portfolio Projects Management Division.

Transmission Business Unit

The Transmission Business Unit plans, designs, constructs, operates, and maintains transmission facilities throughout the province and provides licensing and environmental assessment services, and detailed system planning analysis. In addition, the Business Unit is responsible for HVDC systems, and for the installation and maintenance of electrical apparatus in stations. Moreover, the Business Unit is responsible for real-time operation and reliability of the power grid and provides transmission services to third party open-access transmission customers. The Transmission Business Unit consists of the Apparatus Maintenance Division, the HVDC Division, the Transmission Construction & Line Maintenance Division, the Transmission Planning & Design Division, and the Transmission System Operations Division.

Customer Service & Distribution Business Unit

The Customer Service & Distribution Business Unit (CS&D) provides Manitoba customers with safe, reliable, economical, and innovative energy products and services through the engineering, construction, operation and maintenance of Manitoba Hydro's natural gas and electrical distribution network (66kV and below). The Business Unit plans for the long-term necessary capacity to accommodate customer growth. Moreover, the Business Unit improves the distribution system through asset replacements and system upgrades. The Business Unit consists of the Customer Service Operations South Division, the Customer Service Operations Winnipeg & North Division, the Distribution Engineering & Construction Division, and Business Support & Capital Asset Management Division.

Customer Care & Energy Conservation Business Unit

The Customer Care & Energy Conservation Business Unit provides energy services and support to meet the needs of customers within Manitoba, captures Demand Side Management opportunities, and secures the natural gas needs of the province. This Business Unit is the primary contact between Manitoba Hydro and its domestic customers. The Customer Care & Energy Conservation Business Unit includes the Business Communications Department, the Business Support Services Division, the Consumer Marketing and Sales Division, the Gas Supply Division, the Industrial & Commercial Solutions Division, the Power Smart Planning, Evaluation, & Research Department, and the Affordable Energy Department.

Human Resources & Corporate Services Business Unit

The Human Resources & Corporate Services Business Unit provides services in the areas of human resources, information technology (IT), workplace health and safety, and environmental management. The Business Unit consists of the Human Resources Division, the IT Division, the Workplace Safety & Health Division, the Corporate Services Division, and the Corporate Environmental Management Department.

Manitoba Hydro

ORGANIZATION STRUCTURE
EXECUTIVE AND SENIOR MANAGEMENT

- BOARD
  - President and Chief Executive Officer — **Scott Thomson**
    - Acting Division Manager Public Affairs — **Scott Powell**
    - Vice-President Human Resources & Corporate Services — **Bryan Luce**
      - Division Manager Human Resources — **Gary Maksymyk**
      - Division Manager Workplace Safety & Health and Corporate Services — **Brad Ireland**
      - Division Manager Information Technology Services — **Glen Reitmeier**
      - Corporate Environmental Management
    - Vice-President Generation Operations — **Lorne Midford**
      - Division Manager Engineering Services — **Joel Wortley**
      - Division Manager Generation North — **John Kreml**
      - Division Manager Generation South — **Robert Dandenault**
      - Division Manager Power Planning — **Joanne Flynn**
      - Division Manager Power Sales & Operations — **David Cormie**
    - Vice-President Major Capital Projects — **Bruce Barrett**
      - Division Manager Bipole III Project — **Rob Elder**
      - Division Manager New Generation Construction — **Angie Adams**
      - Division Manager Portfolio Projects Management — **Eduard Wojczynski**
      - Division Manager Licensing & Relationship Management — **Vicky Cole**
      - Project Services
      - Major Capital Projects Labour Relations
    - Vice-President Transmission — **Shane Mailey**
      - Division Manager Apparatus Maintenance — **Quinn Menec**
      - Division Manager HVDC — **John McNichol**
      - Division Manager Transmission Construction & Line Maintenance — **Glenn Penner**
      - Division Manager Transmission Planning & Design — **Gerald Neufeld**
      - Division Manager Transmission System Operations — **Anthony Clark**
    - Vice-President Customer Care & Energy Conservation — **Lloyd Kuczek**
      - Division Manager Gas Supply — **Vacant**
      - Division Manager Industrial & Commercial Solutions — **Dale Friesen**
      - Division Manager Consumer Marketing & Sales — **Lois Morrison**
      - Division Manager Business Support Services — **Paul Chard**
      - Business Communications
      - Power Smart Planning/Evaluation & Research
      - Affordable Energy
    - Vice-President General Counsel & Corporate Secretary — **Ken Tennenhouse**
      - Division Manager Internal Audit — **Lawrence Wilson**
      - Division Manager Law — **Patti Ramage**
      - Insurance Services
      - Intellectual Property
      - Human Rights & Respectful Workplace
    - Vice-President Corporate Relations — **Ruth Kristjanson**
      - Division Manager Aboriginal Relations — **Elissa Neville**
      - Division Manager Corporate Planning & Strategic Review — **Ian Page**
      - Government Relations & Current Issues
    - Vice-President Customer Service & Distribution — **Brent Reed**
      - Division Manager Distribution Engineering & Construction — **Chuck Steele**
      - Division Manager Customer Service Operations – South Region — **Scott Dunn**
      - Division Manager Customer Service Operations – Winnipeg & North Region — **Dave Case**
      - Division Manager Business Support & Capital Asset Management — **Mark Prydun**
    - Vice-President Finance & Regulatory — **Darren Rainkie**
      - Corporate Controller — **Sandy Bauerlein**
      - Division Manager Rates & Regulatory Affairs — **Greg Barnlund**
      - Corporate Treasurer — **Manny Schulz**
      - Subsidiary Operations — **Shawna Pachal**
      - Corporate Risk Management
      - Financial Planning

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INTEGRATED FINANCIAL FORECAST & ECONOMIC OUTLOOK

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INTEGRATED FINANCIAL FORECAST & ECONOMIC OUTLOOK

3.0 OVERVIEW

Tab 3 provides an overview of Manitoba Hydro's Integrated Financial Forecast, Economic Outlook, and Debt Management Strategy. Section 3.1 discusses the 2014 Economic Outlook, Sections 3.2 and 3.3 discuss Manitoba Hydro's 2014 Integrated Financial Forecast (IFF14) and Electric operations forecast (MH14), Section 3.4 discusses Manitoba Hydro's 20 year Financial Outlook and Financial Targets, Section 3.5 discusses Manitoba Hydro's Debt Management Strategy, and Section 3.6 discusses Credit Rating Agency Reports.

The key conclusions with respect to Tab 3 are:

1. The required investments in new and existing infrastructure that are necessary to continue to provide a high level of service to customers are expected to double the asset base and carrying costs of Electric operations in the next 10 years.

2. While a portion of the required investments will be funded by cash flow from operations, the majority will be funded through unprecedented levels of debt financing.

3. Rate stability for customers is dependent on Manitoba Hydro maintaining its financial strength.

4. The required investment in assets will place pressure on Manitoba Hydro's financial strength by deteriorating the financial results and key financial ratios.

5. While Manitoba Hydro is prepared to accept deterioration of its financial ratios in order to mitigate rate increases for customers, the proposed 3.95% rate increases are the minimum that are required to maintain rate stability and

manage the deterioration in the Corporation's financial strength during the period of extensive investments.

6. The proposed 3.95% rate increases will maintain Manitoba Hydro's 2015/16 and 2016/17 net income and financial ratios at acceptable levels and will compensate for lower net extraprovincial revenues that are currently being experienced.

7. The proposed 3.95% rate increases are required notwithstanding more favourable near-term financial results, given Manitoba Hydro's near-term exposure to changes in water flow conditions and the mid-term outlook for less favourable financial results.

8. Inflationary rate increases are not sufficient to maintain rate stability for customers, and will subject customers to increased rate volatility in the future.

9. The key financial risks associated with rate increases lower than 3.95% are:
    i. Increased risk to customers of rate instability and rate shock;
    ii. Increased borrowing requirements and associated financing costs which must be recovered from customers in the future;
    iii. Potential negative implications to the Provincial credit rating and Manitoba Hydro's borrowing costs.

3.1 ECONOMIC OUTLOOK 2014

The Economic Outlook is prepared at the start of the annual forecasting cycle at Manitoba Hydro. The forecasts reported in the Economic Outlook are based on a consensus view of several independent sources including Canada's primary financial institutions in addition to several other independent sources, all of which are well known and respected. The most recent forecasts from each of the sources at the end of March 2014 were used in the spring Economic Outlook. The Economic Outlook provides a forecast of economic and financial variables that are used in business analyses throughout the Corporation and are inputs in other forecasts. Variables such as real gross domestic product and residential customer projections are inputs to the Load Forecast; and, interest, escalation and exchange rates are used in a number of component forecasts that are inputs to the IFF. The 2014 Economic Outlook is provided in Appendix 3.1.

With the weakened outlook for global growth, future forecasts for both interest rates and the Canadian dollar were updated in the fall of 2014, with source forecasts available as of the end of September 2014. Also provided in Appendix 3.1 is an update to Appendix A of the 2014 Economic Outlook to reflect the latest consensus of source forecasts as of September 2014.

As a result of the fall update, the values of certain variables that were used in the IFF have been updated from those in the 2014 Economic Outlook. The economic variables that were revised in the fall update and incorporated into IFF14 are as follows:

Figure 3.1 Updated Economic Variables

	Short-term Interest Rate*	Long-term Interest Rate*	USD/CAD
2014/15	1.95	4.50	1.10**
2015/16	2.30	5.10	1.12
2016/17	3.40	5.50	1.12

*Short-term and long-term interest rates include the provincial guarantee fee
** USD/CAD exchange rate marked with an asterisk was reviewed, but not changed from the spring 2014 Economic Outlook for 2014/15.

Appendix 3.2 provides additional information with respect to the determination of Manitoba Hydro's interest rate forecast.

3.2 INTEGRATED FINANCIAL FORECAST

The Integrated Financial Forecast ("IFF") is Manitoba Hydro's primary planning document for projecting the future financial direction of the Corporation. IFF14 sets forth the projected financial results and financial position of Manitoba Hydro for the 20-year period to 2033/34. Its purpose is to provide an indication of the Corporation's long-term financial direction. The IFF serves as the primary forecast to determine the need for rate increases and the detailed forecasts in years two and three of the IFF form the basis of the revenue requirement portion of the Corporation's electric rate application.

The IFF is based on various component forecasts from across the Corporation including the:

– Economic Outlook
– Energy Price Outlook

- Electricity Export Price Forecast
- Power Smart Plan
- Electric Load Forecast
- Domestic Revenue Forecast
- Power Resource Plan
- Generation Cost & Interchange Revenue Forecast
- Capital Expenditure Forecast
- Operating, Maintenance & Administrative Expense Forecast

IFF14 can be found in Appendix 3.3 and was approved by the Manitoba Hydro-Electric Board (“MHEB”) on December 3, 2014. IFF14 includes segment forecasts for electric operations (MH14), natural gas operations (CGM14), and corporate subsidiaries (CS14).

3.3 ELECTRIC OPERATIONS FORECAST (MH14)

The MH14 forecast contains the projected financial results for electric operations and can be found in Appendix 3.4. Manitoba Hydro’s financial targets have been set for consolidated operations. As requested in past proceedings, Manitoba Hydro has also provided financial ratio calculations for electric operations in Appendix 3.4. Given the dominate size of electric operations in relation to consolidated operations, these calculations usually differ only slightly from consolidated ratio calculations.

In this Application, 2015/16 and 2016/17 are the two years for which rate increases are sought. Manitoba Hydro is also seeking final approval of the 2.75% rate increase granted effective May 1, 2014 in Order 49/14. The forecast period for MH14 extends for 20 years, in order to provide an indication of the longer-term financial outlook for electric operations. For the purposes of the requested rate increases, the focus of this Application is centered on the three year period under review in this proceeding (2014/15 to 2016/17) and the first 10 years of MH14 (2014/15 to 2023/24). This follows the Manitoba Hydro approach of determining near-term rate proposals in the context of the 10 year financial outlook and the financial challenges in this period that result from the extensive investment requirements.

The rate increases proposed for 2015/16 and 2016/17 have been approved by the MHEB for submission to the PUB. The indicative rate increases subsequent to 2016/17 may be changed in future forecasts and are presented for illustrative purposes only. Each year’s revision to the Integrated Financial Forecast is based on the current year's assumptions including energy supply and demand, projected interest and escalation rates, projected prices for exported energy, operating and capital forecasts and other factors. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

3.3.1 10 Year Electric Operations Financial Outlook

Figure 3.2 below summarizes the changes in net income between MH14 and MH13 (2013 forecast for electric operations). In comparison to MH13, Electric operations net income including the proposed and indicative rate increases is projected to be approximately $0.5 billion lower over the 10-year period to 2023/24.

Figure 3.2 - Comparison of Electrical Operations MH14 to MH13
Increase/(Decrease)
(millions of $)

	2015-2017			2015-2024		
	MH14	MH13	Variance	MH14	MH13	Variance
General Consumers at projected rates	4 430	4 550	(119)	17 755	18 460	(705)
Extraprovincial	1 293	1 134	159	6 449	5 892	557
Other	43	40	3	149	158	(9)
Total Revenues	5 766	5 724	43	24 353	24 495	(142)
Operating and Administrative	1 579	1 584	(5)	5 751	5 821	(71)
Finance Expense	1 553	1 579	(26)	8 975	8 564	411
Depreciation and Amortization	1 228	1 325	(97)	5 486	5 451	36
Water Rentals and Assessments	359	345	14	1 213	1 186	28
Fuel and Power Purchased	456	504	(49)	2 091	2 209	(118)
Capital and Other Taxes	327	331	(4)	1 355	1 350	5
Corporate Allocation	25	27	(1)	83	88	(5)
Other Expenses	7	0	7	25	0	25
	5 534	5 695	(161)	24 980	24 668	311
Non-controlling Interest	45	57	(12)	68	88	(21)
Net Income	277	86	191	(559)	(85)	(474)

The decrease in General Consumers Revenue in the first ten years of MH14 is primarily due to increased energy and capacity savings as a result of more aggressive Residential and Commercial incentive based DSM programs, alternative approaches to the market, and additional new energy efficiency programs.

The increase in Extraprovincial Revenue in the first ten years of MH14 is primarily due to a projected weakening of the Canadian dollar compared to MH13, as well as increased DSM energy and capacity savings, which increase export sales. These increases in Extraprovincial Revenue are partially offset by lower projected export prices compared to MH13.

The decrease in OM&A in the first ten years of MH14 is mainly due to the reclassification of Great Northern Transmission Line costs to fuel and power purchases, as well as the nine month deferral of Bipole III Reliability Project.

The increase in Finance Expense in the first ten years of MH14 is primarily due to an increase in interest expense associated the revised capital spending for the Bipole III Reliability Project and the Keeyask Generating Station when these projects are placed into service and the interest is no longer capitalized. This increase is partially offset by lower projected interest rates compared to MH13.

The increase in Depreciation and Amortization Expense in the first ten years of MH14 is primarily due to the revised capital spending noted above, and is almost fully offset by the reduction in depreciation rates as a result of the 2014 Depreciation Study and changes to depreciation methodologies.

The decrease in Fuel and Power Purchased in the first ten years of MH14 is primarily a result of the following: a reduction in import purchases and thermal generation requirements due to increased DSM energy and capacity savings, lower import and fuel prices, and lower transmission charges. Decreases in Fuel & Power Purchased are partially offset by a projected weakening of the Canadian dollar compared to MH13.

Tab 5 of the Application provides detailed explanations of the actual and forecast revenues and expense related to Electric operations for 2012/13 to 2016/17.

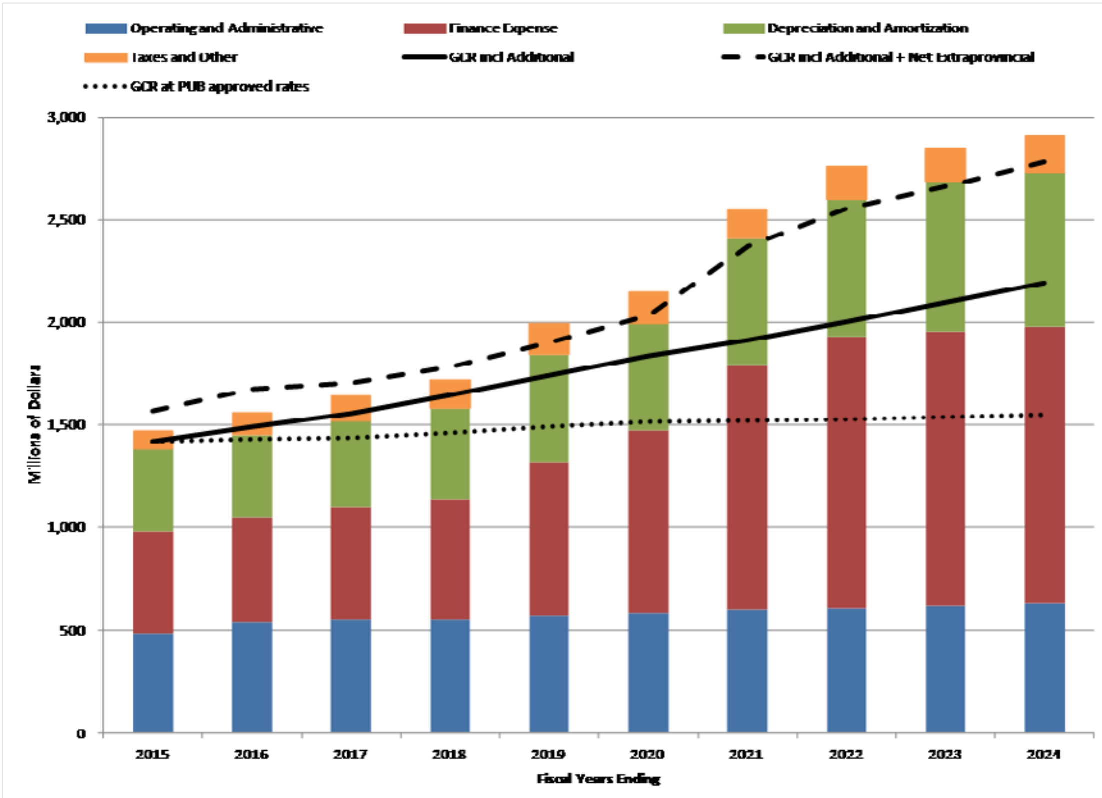
3.3.2 10 Year Comparison of Expenses Versus Revenues—Electric Operations

The following Figure 3.3 compares Manitoba Hydro’s electric operations projected non-flow related expenses (OM&A, finance expense, depreciation expense, and taxes and other expenses), which are more fixed in nature, to the Corporation’s projected domestic and net export revenues (extraprovincial revenues less fuel & power purchases and water rentals & assessments). Manitoba Hydro's costs rise sharply to approximately $3.0 billion over the 10 year period to 2023/24, essentially doubling from their current level of $1.5 billion. This increase in costs is primarily driven by Manitoba Hydro's required capital investments.

General Consumers Revenue is insufficient to fully cover the $1.5 billion total cost increase. Over the 10 year period, General Consumers Revenue, including the proposed and projected indicative annual rate increases, rises by only about half the cost increase ($0.7 billion and $1.5 billion respectively). Even with net extraprovincial revenues, Manitoba Hydro is projecting losses on electric operations in 2018/19 to 2023/24 totaling approximately $0.9 billion, which reduces projected retained earnings from approximately $2.7 billion in 2014/15 to $2.0 billion by 2023/24.

Manitoba Hydro is relaxing its adherence to financial targets over this period in order to alleviate rate increases in excess of 3.95% to the extent possible. Due to the deterioration in Manitoba Hydro's financial ratios (discussed in Section 3.4), any further increases to costs or reductions to revenues increases the risk of significantly higher rate increases to customers.

Figure 3.3 Electric Expenses Compared to Revenues



In the next 10 years there is significant financial risk and potential for rate volatility as Manitoba Hydro's financial position deteriorates due to the large capital investment requirements. In the longer term, the indicative 3.95% rate increases and the additional export revenues from Keeyask are forecast to accumulate to a sufficient level to cover the increased costs and Manitoba Hydro is projected to begin to rebuild its financial reserves.

3.3.3 Sensitivity Analysis

Manitoba Hydro's earnings and financial reserves are highly sensitive to fluctuations in water flows, interest rates, export prices, and domestic rates changes. The Sensitivity Analysis discussion on pages 22-25 in Appendix 3.3 and provided in Appendix 3.6 show the following impacts to retained earnings associated with changes to these assumptions (assuming there are no compensating changes to the projected rate increases reflected in MH14):

- A 5 year drought would result in a significant detrimental impact to Manitoba Hydro's financial stability causing a decrease in retained earnings of $1.7 billion by 2020/21 (the end of the 5 year drought period).

- A change in interest rates by +/- 1% would cause retained earnings to change by approximately +/- $1 billion by 2023/24.
- A low or high export price change would cause retained earnings to change by approximately +/- $700 million by 2023/24.

Although MH14 shows a strengthening of earnings in the first four years of the forecast to 2017/18, Manitoba Hydro's projected financial results and ratios (discussed in detail in Section 3.4) show a projected decline over this period and continuing through to the in-service of the Keeyask Generating Station. It is imperative for Manitoba Hydro to be granted the proposed rate increases, as well as regular and reasonable rate increases over the long term to maintain Manitoba Hydro's financial integrity and self-sufficiency, ensure rate stability for its customers, to maintain its infrastructure and to accommodate capital development to provide adequate supply, transmission and distribution into the future.

By receiving regular and reasonable rate increases, as forecast in MH14, Manitoba Hydro will continue to effectively manage the growing electricity requirements of the Province, strive to maintain system reliability and the financial strength of the Corporation on behalf of its customer base.

3.4 20 YEAR FINANCIAL OUTLOOK & FINANCIAL TARGETS

Over the 20-year period to 2033/34, electric operations net income in MH14 is projected to be approximately $1.8 billion lower than MH13. General Consumers Revenue is $3.3 billion lower compared to MH13 mainly due to increased demand side management savings, a lower approved rate increase for 2014/15 and lower projected indicative rate increases from 2031/32 to 2033/34. Over the 20 year forecast period, net extraprovincial revenues are projected to be $2.0 billion lower compared to MH13 mainly due to the suspension of Conawapa, as well as lower projected export prices, partially offset by increased energy available for export as a result of increased demand side management (DSM) energy and capacity savings.

The reduction in General Consumers Revenue and extraprovincial revenues is partially offset by reductions in finance expense ($2.6 billion), capital and other taxes ($0.4 billion), and depreciation expense ($0.2 billion) compared to MH13 that result from lower projected interest and depreciation rates and projected capital expenditures that are

$7.5 billion lower over the 20 year period to 2033/34 mainly due to the suspension of Conawapa. OM&A expenses are reduced by $0.4 billion mainly due to the reclassification of Great Northern Transmission line costs.

3.4.1 Consolidated Financial Targets

Manitoba Hydro has three primary financial targets for consolidated operations which are used to assess the financial strength of the Corporation.

1. Debt/Equity: Maintain a minimum debt/equity ratio of 75:25.
2. Interest Coverage: Maintain a minimum annual gross interest coverage ratio of greater than 1.20.
3. Capital Coverage: Maintain a capital coverage ratio of greater than 1.20 (excepting new major generation and transmission).

The Corporation has commenced construction on the Bipole III Reliability and Keeyask generating station projects. It is recognized that it may not be possible to maintain financial targets during this period of major investment in the generation and transmission system and that financial ratios will deteriorate during this investment period, even with the proposed and indicative rate increases of 3.95%.

Manitoba Hydro recognizes that the rate increases that would be necessary to maintain its financial ratios at or above targets in the near to medium term, would be financially challenging for its customers. Further, this would be inconsistent with Manitoba Hydro's approach of smoothing rate increases over time in order to promote rate stability. Consequently in MH14, financial results and ratios are projected to be significantly below target for an extended period of time. Notwithstanding Manitoba Hydro's desire to smooth rate increases to customers over time, the Corporation recognizes that the 3.95% rate increases are the minimum that are required to maintain rate stability and financial integrity.

The PUB expressed concern with respect to the adequacy of Manitoba Hydro's financial reserves when it found in Order 43/13, page 23:

> *"Manitoba Hydro currently has achieved its debt-to-equity target of 75:25. However, the Board is concerned about the contemplated deterioration in the utility's financial targets, particularly the fact that by 2021, the debt-to-equity ratio is projected to be*

> *90:10. Any further escalations in the capital cost for Manitoba Hydro's major new capital projects will cause the financial structure to deteriorate further.*
>
> …
>
> *The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates. The Board sees a need to further examine and quantify the other risks that Manitoba Hydro faces at the next General Rate Application and determine whether these should be subject to separate reserve provisions. The Board will require Manitoba Hydro to provide an analysis of risks on a quantitative and probabilistic basis at the next General Rate Application.*
>
> *The Board notes that Manitoba Hydro shares the benefit of the flow-through credit rating of the Province, which affords it preferential interest rates on its debt and access to funds to meet its major capital spending program. However, as its debt grows, there is a potential for Manitoba Hydro's financial condition to affect the credit rating of the Province. It is important that Manitoba Hydro remains a financially strong and viable organization."*

Manitoba Hydro has recently commenced a review of its financial targets and KPMG has been selected as the consultant to provide recommendations to Manitoba Hydro on the appropriate financial targets which align with the mandate of the Corporation and the interests of its stakeholders considering its operating and business outlook and associated risks. The review will consider the objectives of maintaining rate stability for customers and Manitoba Hydro's self-supporting status for credit rating proposes. It is expected that this review will be completed in time for the approval of IFF15 by the MHEB in late fall of 2015.

As part of this review, analysis will also be provided to satisfy PUB Directive 10 from Order 43/13 to review Manitoba Hydro's operating and financial risks in order to assess the adequacy of financial reserves, including, as appropriate, the use of quantitative and probabilistic analysis. It is expected that this information would be available for review by the PUB at the next GRA proceeding.

Manitoba Hydro has filed extensive information in Appendices 3.5 and 3.6 of the Application with respect to the financial impacts of the key risks of the Corporation, as well as the financial implications of various alternative rate scenarios. Manitoba Hydro is of the view that this information provides adequate support for the PUB to approve Manitoba Hydro's Application for 2015/16 and 2016/17.

The 3.95% proposed and indicative rate increases are the minimum necessary to manage the significant deterioration in Manitoba Hydro's projected financial results and ratios in the next 10 year period. Should the PUB defer the proposed rate increases, there is greater risk that future rate increases will be significantly higher than 3.95%.

3.4.2 Equity Ratio

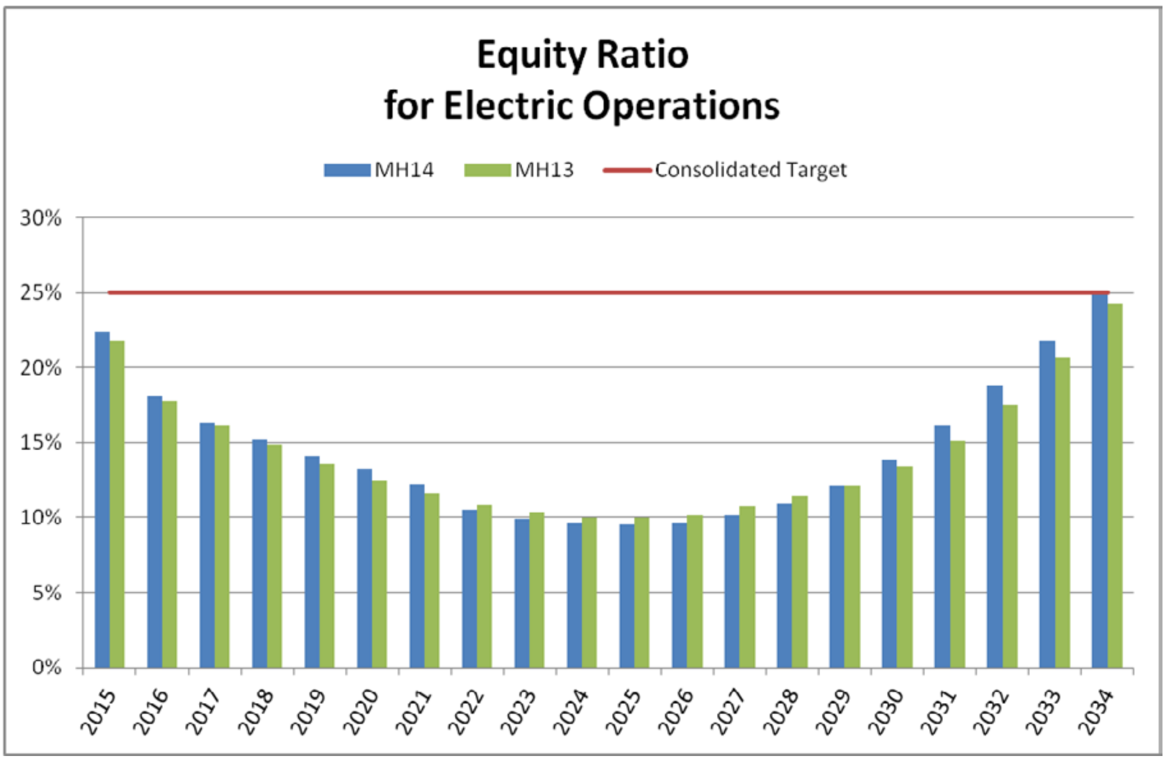
Manitoba Hydro's consolidated debt/equity target is to maintain a minimum debt to equity ratio of 75:25 (i.e. 75% debt and 25% equity). The equity ratio measures the portion of assets that have been financed by internally generated funds (equity) rather than debt. Manitoba Hydro's equity is not a cash reserve but is primarily represented by the internally generated funds accumulated since its inception that have been reinvested in the assets of the Corporation.

It is beneficial for customers when assets are funded through internally generated funds rather than debt in that Manitoba Hydro must collect the carrying costs on debt through rates. The ability to fund a portion of assets through internally generated funds is also beneficial in that it preserves borrowing capacity in the event of any adverse financial impact. It is very important that Manitoba Hydro achieve an appropriate balance of debt and equity such that the Corporation can continue to invest in its system without driving its debt to unacceptable levels or dramatically impacting customers' rates.

Should the capital markets perceive Manitoba Hydro's debt levels to be too high, there may be negative implications to the Province's credit ratings, which could result in higher borrowing costs. An appropriate debt/equity target, assists Manitoba Hydro to maintain reasonable levels of debt and equity in proportion to the assets the Corporation has invested in, in order to keep debt and borrowing costs at manageable levels. As a result of the significance of the size of Manitoba Hydro's debt in relation to the Province of Manitoba's debt as a whole, the debt/equity ratio is a key indicator in the review of Manitoba Hydro for the Province's credit rating.

Figure 3.4 below provides the projected electric operations equity ratio for MH14 compared to MH13. Manitoba Hydro's electric operations equity ratio was 23% at March 31, 2014. The debt/equity ratio is projected to weaken substantially over the next several years to 10% by 2022/23 (the same level as MH13) mainly due to the significant capital investment in major new generation and transmission and expenditures to renew and replace aging infrastructure. The equity ratio is projected to return to the 25% target by 2033/34 (the same year as in MH13) due to the regular and reasonable rate increases that are included in the forecast, as well as export revenues resulting from the Keeyask Generating Station.

Figure 3.4 Projected Equity Ratio



In Manitoba Hydro's judgment, the projected deterioration in the equity ratio in MH14 is at the minimum acceptable financial operating level even with the proposed and indicative rate increases. Any further deterioration in the equity ratio significantly increases the risk of large rate increases to customers in the longer term and any reduction to the rate increases proposed in this Application only intensifies this risk to customers. As an example, the impact of the reoccurrence of the historic 5-year drought would result in significant further deterioration in the equity ratio from MH14 and essentially deplete Manitoba Hydro's financial reserves. In this circumstance, there would not be sufficient reserves to mitigate the potential financial impacts of the considerable array of the risks the Corporation faces in fulfilling its mandate.

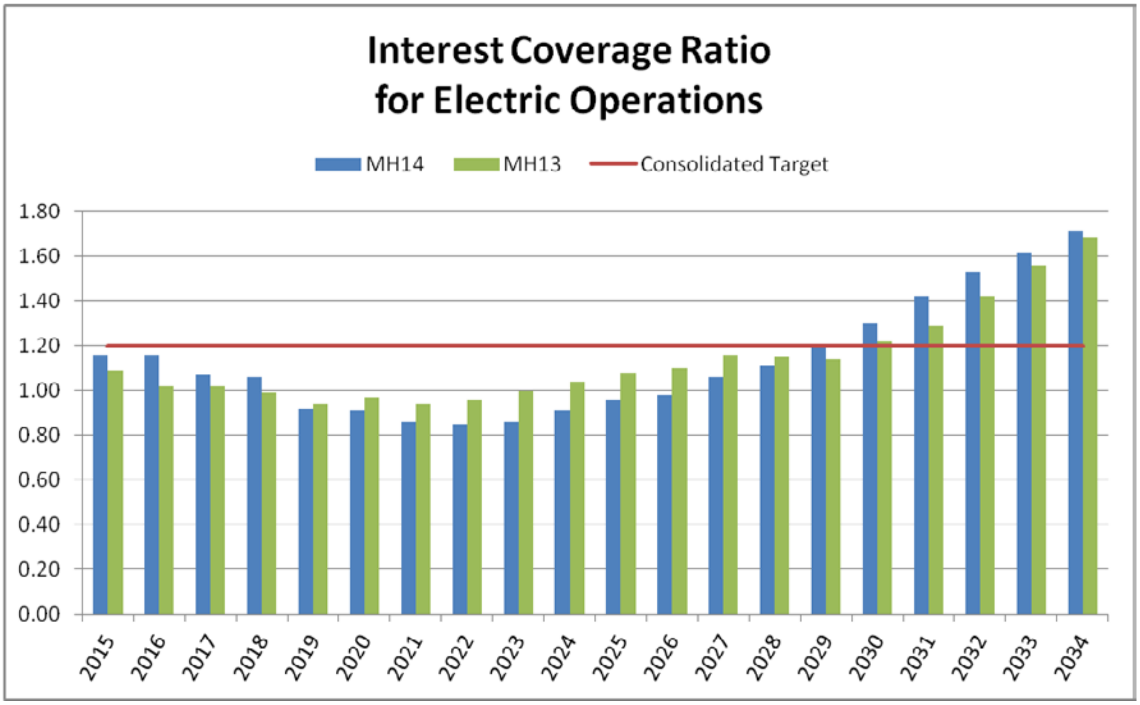
3.4.3 Interest Coverage Ratio

Manitoba Hydro's consolidated target is to maintain a minimum annual gross interest coverage ratio of greater than 1.20. The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Annual interest coverage at or greater than 1.20 ensures that there is a sufficient margin of earnings in excess of that which is required to cover interest payments to bondholders.

Manitoba Hydro's interest coverage ratio is also forecast to be well below target for several years of the forecast. In eight years of the forecast, Manitoba Hydro's interest coverage ratio is below 1.0, which indicates that the utility would experience elevated operational liquidity risk and may have difficulty generating sufficient revenues and cash flow from operations to pay its interest obligations.

Figure 3.5 below provides the projected electric operations interest coverage ratio for MH14 compared to MH13. Manitoba Hydro's electric operations interest coverage ratio was 1.25 at March 31, 2014. Lower net earnings and higher finance expenses associated with the higher capital costs of Bipole III, DSM, Keeyask and aging infrastructure renewal and replacement results in projected interest coverage ratios lower than target for a period of fourteen years, and below 1.00 for eight of those years, before returning to target in 2028/29.

Figure 3.5 Projected Interest Coverage Ratio



4.4.4 Capital Coverage Ratio

Manitoba Hydro's consolidated target is to maintain a capital coverage ratio of greater than 1.20. The capital coverage ratio measures the ability of current period internally generated funds to finance sustaining capital expenditures (excluding major new generation and transmission capital expenditures). A capital coverage ratio of greater than 1.20 provides sufficient cash flow from operations to fund sustaining capital expenditures and further reduces the need for debt financing.

Similar to the interest coverage ratio, a lower capital coverage ratio indicates that the utility has less revenues or more operating or finance expenses resulting in less cash flow from operations to fund sustaining capital expenditures. A capital coverage ratio of less than 1.0 indicates that the utility is having difficulty generating sufficient revenues required to fund its sustaining capital expenditures and must borrow more debt in order maintain the same level of expenditures and customer service. The capital coverage ratio is a measure that assists in keeping Manitoba Hydro's debt and finance expense at manageable levels.

Figure 3.6 below provides the projected electric operations capital coverage ratio for MH14 compared to MH13. Manitoba Hydro's electric operations capital coverage ratio was 1.39 at March 31, 2014. Capital coverage is projected to be below target for nine years of the forecast, and below 1.00 for six of those nine years, due to the reduction in net income and increasing capital requirements to replace aging infrastructure. The capital coverage ratio is projected to return to target by 2023/24 and then projected cash flows are sufficient to enable this target to be met in the remaining years of the forecast.

Figure 3.6 Projected Capital Coverage Ratio

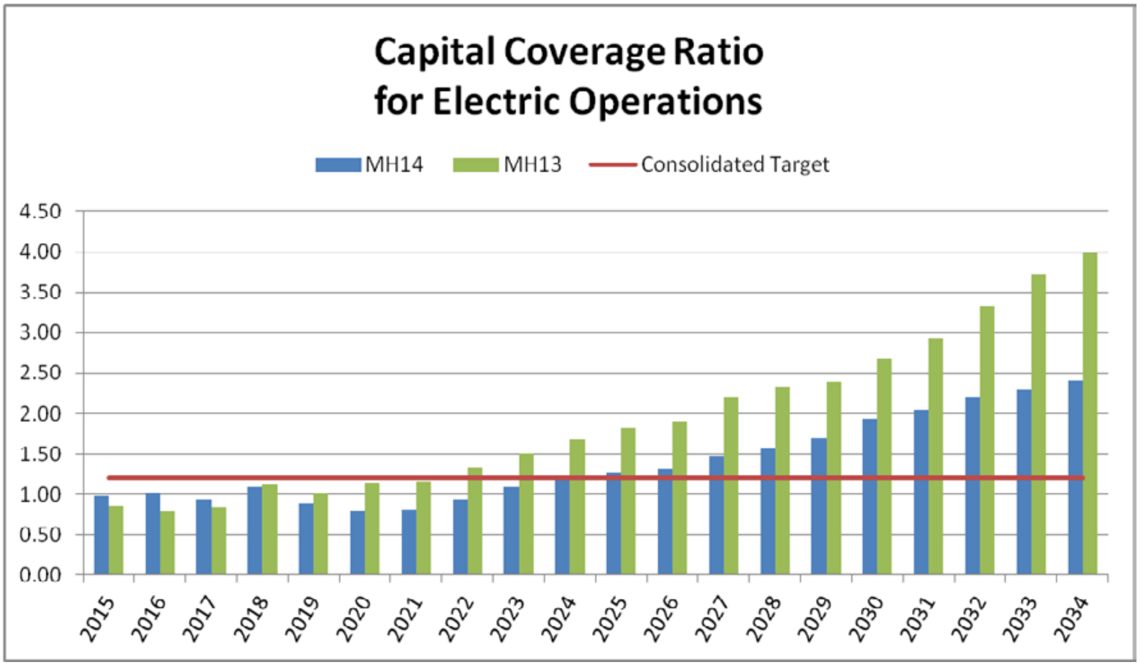
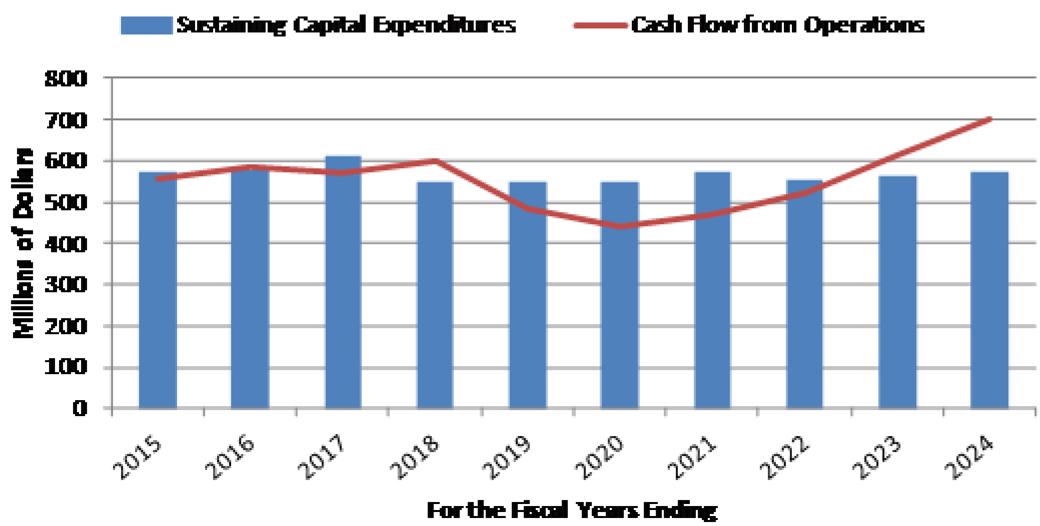


Figure 3.7 below shows the relationship between sustaining capital expenditures and cash flow from operations for MH14. Although revenues (Manitoba and extraprovincial) are increasing gradually over MH14, cash flow from operations is relatively flat over the first four years and then declines for a short period to 2019/20.

Until such time as there are sufficient internally generated funds in 2022/23, there is a cumulative sustaining capital expenditure funding deficit of $300 million which results in incremental borrowing for Manitoba Hydro. Following the in-service of the Keeyask Generating Station, revenues are projected to be sufficient to generate a surplus of cash flow from operations in excess of sustaining capital expenditures. In the interim, until the Keeyask Generating Station is generating revenue, any further reduction in revenues or increases in capital expenditures will result in further capital coverage ratio deterioration which increases the risk of significant rate increases to customers in the future.

Figure 3.7 Sustaining Capital Expenditures and Cash Flow from Operations



3.5 DEBT MANAGEMENT STRATEGY

The Debt Management Strategy document (see Appendix 3.7) provides information on the historical growth of the Corporation's investment in fixed assets and the corresponding increase in Manitoba Hydro's long term debt. The document also summarizes the statutes that govern the Corporation's financing programs, and outlines the debt management strategies that will address the Corporation's financing requirements for the 2014/15, 2015/16 and 2016/17 fiscal years.

Manitoba Hydro's fundamental debt management objective is to provide stable, low cost funding to meet the financial obligations and liquidity needs of the Corporation.

The low interest rate environment over the past few years has provided the opportunity for Manitoba Hydro to secure stable, low cost funding. Since 2006/07, the debt portfolio's net weighted average interest rate has decreased by nearly 2.0%. To enhance the debt portfolio stability, the weighted average term to maturity of the Corporation's debt portfolio has increased by over three years.

In order to mitigate refinancing risk, to maintain financing flexibility during the upcoming decade, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term fixed rate financings with maturities of 10 years and longer.

3.6 CREDIT RATING AGENCY REPORTS

Manitoba Hydro uses debt advanced and guaranteed by the Province of Manitoba to finance its investment in assets. Manitoba Hydro's long and short term credit ratings are a flow-through of the Province of Manitoba's credit ratings (as highlighted in green in Figure 3.8 below):

Figure 3.8: Province of Manitoba Credit Ratings

S&P		Moody's		DBRS	
Long Term	Short Term	Long Term	Short Term	Long Term	Short Term
AAA	A-1+	Aaa	P-1	AAA	R-1 high
AA+		**Aa1**		AA high	
AA		Aa2		AA	**R-1 middle**
AA-		Aa3		AA low	
A+	A-1	A1		**A high**	R-1 low
A		A2		A	
A-	A-1/ A-2	A3	P-1/ P-2	A low	
BBB+	A-2	Baa1	P-2	BBB high	R-2 high
BBB	A-2/ A-3	Baa2	P-2/ P-3	BBB	R-2 middle
BBB-	A-3	Baa3	P-3	BBB low	R-2 low/ R-3

The Province of Manitoba has a high credit rating as can been seen in the following chart that shows the long term credit ratings for each of the Canadian provinces. This high credit rating benefits Manitoba Hydro's customers by reducing the cost of borrowing that the Corporation must recover in its rates.

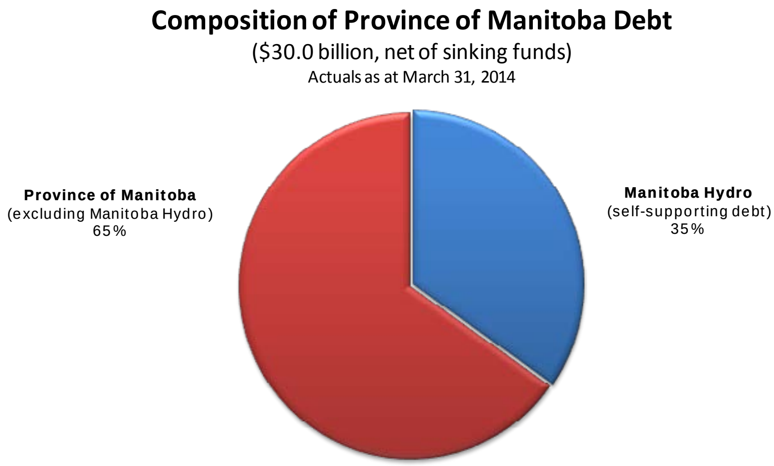
Figure 3.9: Provincial Long Term Credit Ratings Comparison

Province	Standard & Poors	DBRS	Moody's Investors Service
British Columbia	AAA	AA (high)	Aaa
Saskatchewan	AAA	AA	Aaa
Alberta	AAA	AAA	Aaa
Manitoba	AA	A (high)	Aa1
Ontario	AA-	AA (low)	Aa2
Nova Scotia	A+	A (high)	Aa2
Newfoundland & Labrador	A+	A	Aa2
Québec	A+	A (high)	Aa2
New Brunswick	A+	A (high)	Aa2
Prince Edward Island	A	A (low)	Aa2

Rating reports are issued to individual provinces and not necessarily at the same time.

As demonstrated in Figure 3.10, debt advances to Manitoba Hydro form a significant portion of the total provincial debt and the Corporation's financial performance is therefore a contributing factor toward the financial strength and stability of the Province's credit rating.

Figure 3.10 Composition of Province of Manitoba Debt



The credit rating agencies view Manitoba Hydro to be financially self-supporting in that the Corporation is able to meet its financial obligations based on its own revenues without being supported by the tax-base of the Province. As noted by Moody's Investors Service ("Moody's") in a credit analysis on the Province of Manitoba (September 5, 2012):

> "Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting. This Crown Corporation's ability to meet its own financial obligations, without recourse to provincial subsidies is a positive credit attribute for the province."

Credit rating agencies view Manitoba Hydro's current low rates and reasonable regulatory framework as positive ratings considerations. According to Moody's (reports dated October 17, 2014 and November 6, 2014):

> "The province issues debt on behalf of its wholly-owned utility company Manitoba Hydro, which we view as a self-supporting entity and therefore,

> exclude the related net debt from the Province of Manitoba’s debt metrics. … The anticipated increase in debt at Manitoba Hydro could increase the contingent liability for the province of Manitoba in the next few years. … We will monitor the increase in Manitoba Hydro’s debt ratios and the progress of construction of these projects. … We note positively, that Manitoba Hydro has flexibility to increase utility rates given fairly low rates compared to other provinces and that it has already negotiated future long-term export contracts with customers in the US.”
>
> “Manitoba Hydro operates in a stable regulatory framework with steady yearly rate increases. It forecasts annual rate increases of 3.95% until FY2033 to contribute to replacing aging generation, transmission and distribution facilities. The rates are set on a cost-of-service basis. The MPUB independently overseas the rate setting process and has a supportive environment for cost recovery. Residents of Manitoba continue to pay rates that are among the lowest in North America. Revenues from exports to the US and other Canadian provinces accounts for over 20% of electric revenue, alleviating pressure of rate hikes and contributing to the current low rates in the Province.”

Attached for information as Appendix 3.8, are the following credit reports that have recently been issued by DBRS and Moody’s for Manitoba Hydro and the Province of Manitoba:

- DBRS Province of Manitoba October 17, 2014
- DBRS Manitoba Hydro October 23, 2014
- Moody’s Province of Manitoba October 17, 2014
- Moody’s Manitoba Hydro November 6, 2014

Manitoba Hydro is awaiting permission from Standard & Poor’s to provide copies of the most current credit rating reports.

While Moody’s reaffirmed the Province of Manitoba’s credit ratings, they revised the outlook on the Province of Manitoba's Aa1 long term debt ratings from stable to negative. Moody's P-1 short term rating on the Manitoba Hydro-Electric Board's commercial paper program was not affected. Credit ratings and outlooks from S&P and DBRS remained unchanged.

It is important that credit rating agencies continue to view Manitoba Hydro's debt as self-supporting and that weakened financial ratios as a result of major capital investments and reinvestments do not negatively impact the credit rating of the Province.

The proposed rate increases are necessary to continue to demonstrate to the credit rating agencies that the regulatory framework in Manitoba is supportive of Manitoba Hydro's self-supporting financial status.

ECONOMIC OUTLOOK

2014-2035

ECONOMIC ANALYSIS DEPARTMENT

SPRING, 2014

EO14-1

CONTENTS

PREFACE

This information in the Economic Outlook is used in several areas of the corporation; for example, in load forecasting, project evaluation, and financial planning.

The document is derived from the following sources: IHS Global Insight, the Conference Board of Canada, Spatial Economics, BMO Nesbitt Burns, CIBC, Desjardins, Laurentian, Royal Bank of Canada, Scotiabank, National Bank, and TD Bank. As a final step prior to publication, the forecast is refined to reflect information available in early spring.

This forecast is based on what was known and could reasonably be foreseen at the time of its preparation. Users should be cognizant that conditions can and do change and should apply sensitivity analysis accordingly.

The variables are presented in both calendar year and fiscal year format. Fiscal year data have been derived from calendar year data. Fiscal year data are presented in Appendix A; the balance of the text relates to calendar year information.

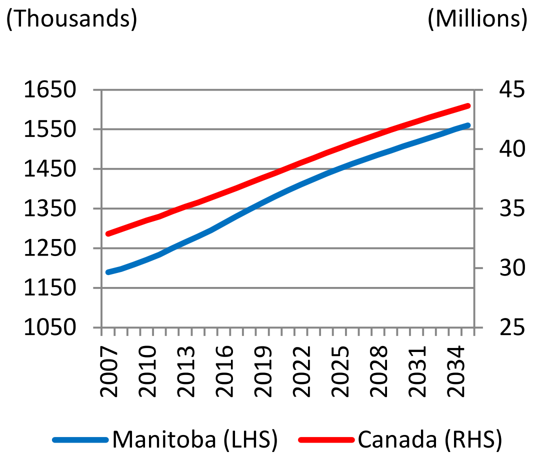
EXECUTIVE SUMMARY

RECENT ECONOMIC PERFORMANCE

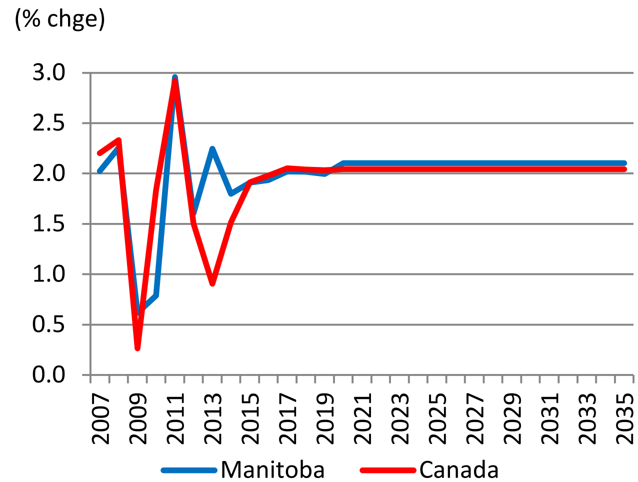
	2009	2010	2011	2012	2013
Manitoba					
Real GDP – % chge	-0.2	2.6	1.7	2.6	2.4
CPI – % chge	0.6	0.8	3.0	1.6	2.2
Population – % chge	0.9	1.0	1.0	1.3	1.2
Employment – % chge	0.0	1.9	0.8	0.9	0.5
Unemployment rate – %	5.2	5.4	5.4	5.3	5.4
Residential customers – '000s	443	447	452	458	464
Housing starts – Units	4,174	5,888	6,083	7,242	7,465
Canada					
Real GDP – % chge	-2.7	3.4	2.5	1.7	2.0
CPI – % chge	0.3	1.8	2.9	1.5	0.9
Population – % chge	1.2	1.1	1.0	1.2	1.2
Employment – % chge	-1.6	1.4	1.6	1.2	1.3
Unemployment rate – %	8.3	8.0	7.5	7.2	7.1
Housing starts – '000s	149	190	194	215	188
90 Day T-Bill rate – %	0.35	0.56	0.93	0.96	0.96
LT Bond 10 Yr+ rate – %	3.77	3.55	3.09	2.25	2.58
C$/US$	1.14	1.03	0.99	1.00	1.03
United States					
Real GDP – % chge	-2.8	2.5	1.8	2.8	1.9
CPI – % chge	-0.4	1.6	3.1	2.1	1.5
GDP Price Deflator – % chge	0.8	1.2	2.0	1.7	1.5
90 Day T-Bill rate – %	0.15	0.13	0.05	0.09	0.05
LT Bond 10 Yr rate – %	3.26	3.22	2.86	1.89	2.41
Unemployment rate – %	9.3	9.6	8.9	8.1	7.4

FORECAST AT A GLANCE

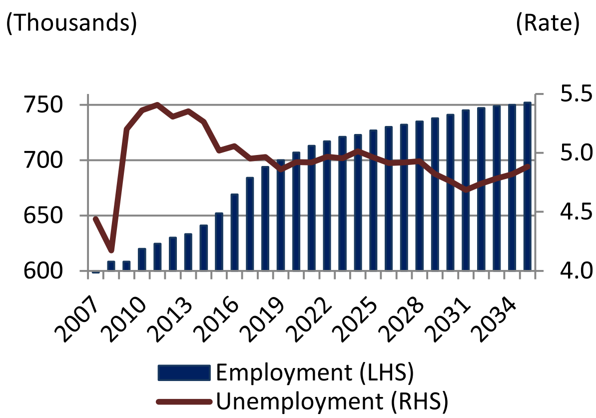
Population



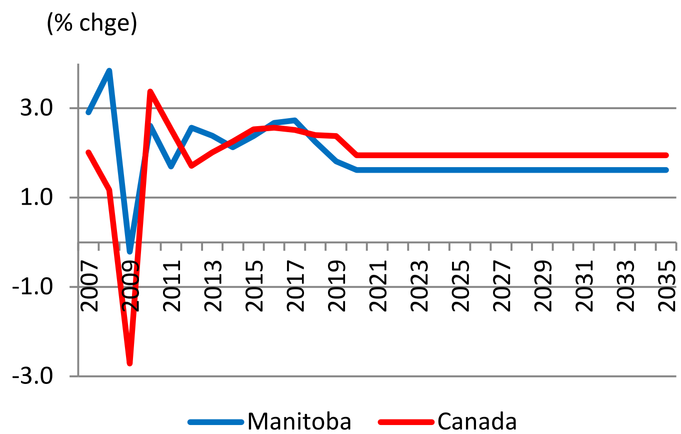
Consumer Price Index



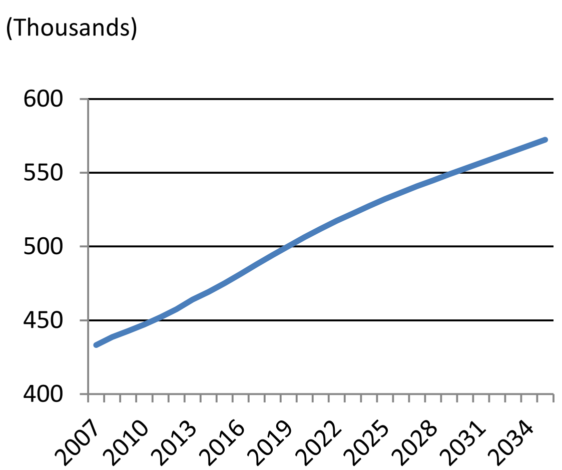
Manitoba Employment



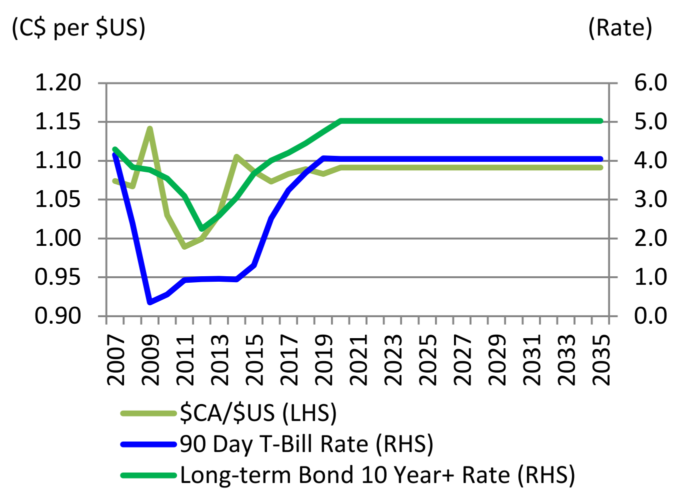
Real GDP Growth Rate



Manitoba Hydro Residential Customers



Canadian Financial Rates



FORECASTS OF KEY ECONOMIC AND FINANCIAL INDICATORS

The forecasts reported in the Economic Outlook are based on a consensus view of several independent sources including Canada's primary financial institutions in addition to several other independent sources, all of which are well known and respected. For the purpose of the 2014 Economic Outlook, the forecasting sources included IHS Global Insight, the Conference Board of Canada, Spatial Economics, BMO Nesbitt Burns, CIBC, Desjardins, Laurentian, Royal Bank of Canada, Scotiabank, National Bank of Canada, and TD Bank.

The following sections of the report provide tables, graphs, and written summaries of the data behind the forecasts for the following key economic indicators:

- Real Gross Domestic Product Growth Rate,
- Pricing – CPI and GDP Implicit Price Deflator,
- Population,
- Employment,
- Housing,
- Short-term and Long-term Interest Rates,
- C$/US$ Exchange Rate, and
- Manitoba Disposable Income.

Appendix A and B of this report provide the history and forecasts for key economic indicators for Manitoba and Canada on a fiscal year basis and a calendar year basis, respectively.

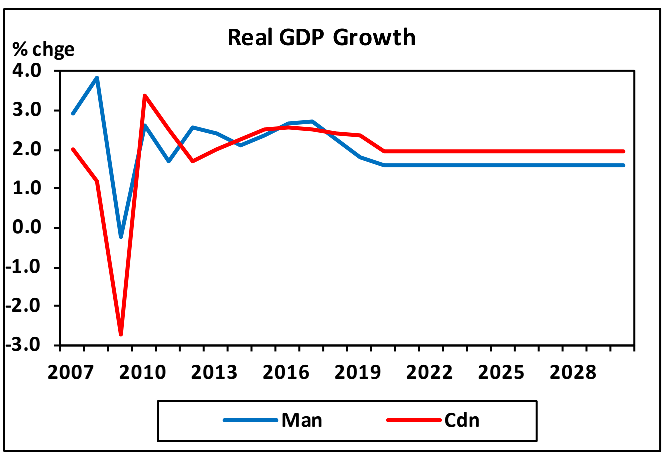
REAL GROSS DOMESTIC PRODUCT

RECENT PERFORMANCE:

Over the past five years (2008-2013) Manitoba has had the third best average annual real GDP growth of the Canadian provinces at 1.8%. In 2013, Manitoba's real GDP increased by 2.4% down from the 2.6% growth it experienced in 2012. Canada's economy grew at a modest 2.0% while the US economy real GDP growth shrank to 1.9% in 2013.

OUTLOOK:

The consensus survey suggests that Government policies are expected to remain tight in the near term causing a fiscal drag on the Manitoba and Canadian economy. EO2014 forecasts that economic growth in Manitoba is expected to continue to slow in 2014, with the economy expanding by 2.1%. The strengthening growth south of the border, however, should boost Manitoba's economy as roughly 70% of the province's exports are to the United States. This should help Manitoba's economy advance to 2.7% by 2016. The drop in long-term growth at 1.6% is based on the assumption that the rest of the world growth will slow down after the medium term recovery.



PRICING: CONSUMER PRICE INDEX AND GDP PRICE DEFLATOR

RECENT PERFORMANCE:

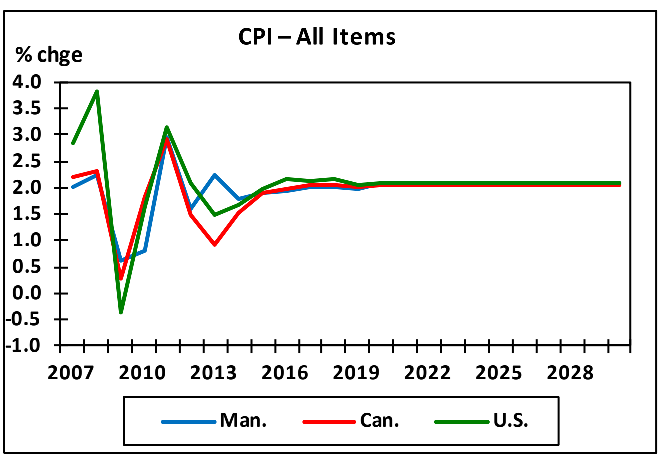
The Consumer Price Index (CPI) is based on a basket of household goods while the GDP price deflator is based on all goods produced domestically. Although inflation is now recovering, within the last year it accelerated faster than anticipated. In Manitoba, tobacco and alcohol, energy, shelter, food, transportation, and household operations boosted overall consumer prices while health and personal care, clothing and footwear, and recreation put downward pressure on prices. In Canada, tobacco and alcohol and energy boosted overall consumer prices while health and personal care, clothing and footwear and recreation put downward pressure on prices. In 2013, Manitoba and Canada CPI increased by 2.2% and 0.9%, respectively, while the U.S. CPI increased by 1.5%. Manitoba and Canadian GDP price deflators increased by 1.3% and 1.2%, respectively, while the U.S. GDP price deflator increased by 1.5% in 2013.

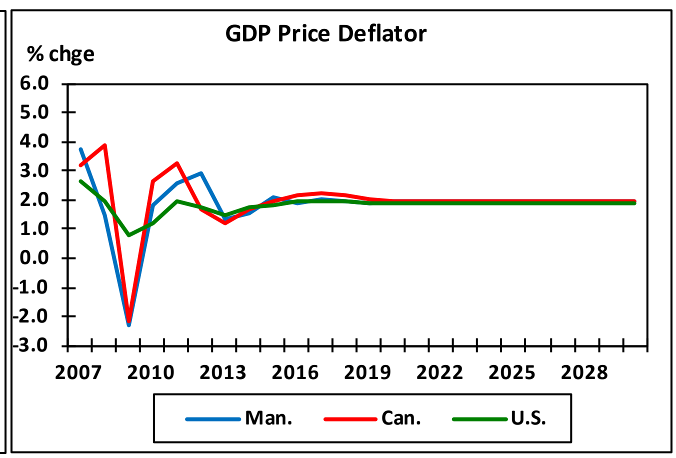
2013 Consumer Price Index
% chge

	Manitoba	Canada
All Items – CPI	2.2	0.9
Food	2.5	1.2
Shelter	3.1	1.3
Household	2.3	1.2
Clothing	1.0	0.1
Transportation	2.2	0.7
Health	-1.6	-0.3
Recreation	0.3	0.3
Other Deflators:		
Energy	3.0	1.5
GDP Deflator	1.3	1.2

OUTLOOK:

The depreciating Canadian dollar is expected to put upward pressure on producer's prices. This, coupled with increasing Manitoba wage rate growth is expected to push Manitoba CPI inflation averaging 2.1% throughout the long-term forecast period. The 2014 Economic Outlook forecasts that Canada and U.S. long-term CPI will be 2.0% and 2.1%, respectively. The 2014 Economic Outlook forecasts that in the long term the Manitoba GDP price deflator will be 1.9%, while Canada and the U.S. GDP price deflator will be 2.0% and 1.9% respectively.





POPULATION

RECENT PERFORMANCE:

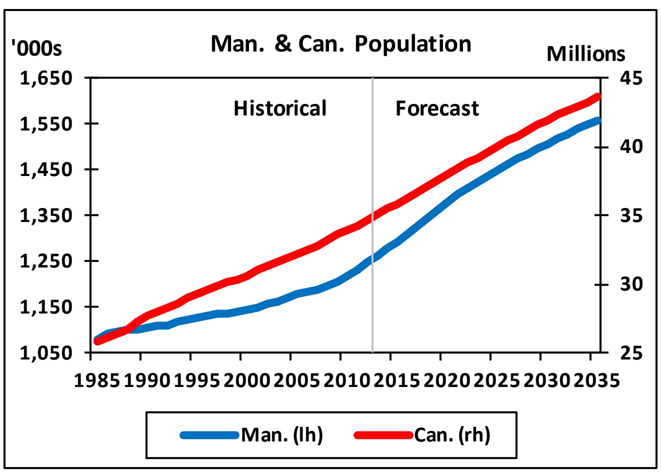
Year	Mb Pop'n. Changes
1995	5,920
1996	5,046
1997	1,932
1998	1,361
1999	4,959
2000	4,865
2001	4,137
2002	5,186
2003	6,892
2004	9,695
2005	5,074
2006	5,228
2007	5,842
2008	8,406
2009	10,815
2010	12,341
2011	12,798
2012	16,304
2013	14,983

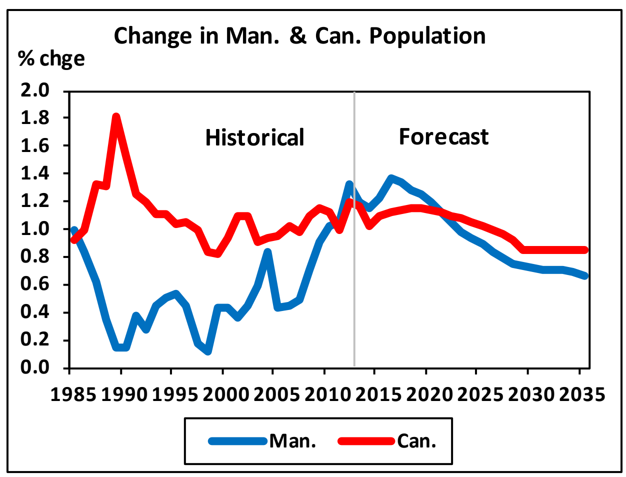
Manitoba's total population increased by 14,983 persons in 2013 or 1.2% relative to 2012. Total net migration to Manitoba was 9,522 people and total natural increase was 5,461 in 2013.

OUTLOOK:

Manitoba's population is expected to grow on average at 0.9% or 13,400 people annually over the forecast period, 1,500 people lower than the growth rate forecast in EO2013. The drop in this year's forecast is due to the international immigration front, with the announcement of the government putting a cap on the number of new applications at 5,000 annually for the Provincial Nominee Program. Despite the above announcement, this year's forecast has two main assumptions: one being the Provincial Nominee Program which will continue to sustain moderate annual growth in immigrants, and two, an "optimal immigration approach" whereby government adjusts future immigration requirements to meet labour market needs. According to Spatial Economics, "the optimal level of immigration is one that facilitates economic growth and minimizes the costs of excess demand for and supply of workers."

Canada's population is expected to grow on average at 1.0% or 386,000 annually over the forecast period. The United States population is expected to grow on average at 0.7% or 2,400,000 people annually.





EMPLOYMENT

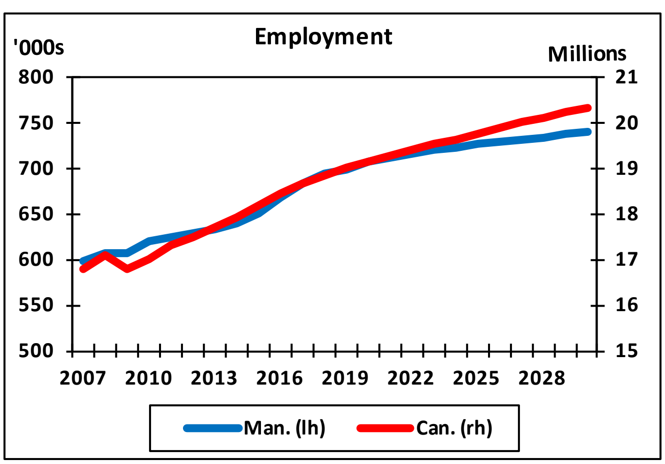
RECENT PERFORMANCE:

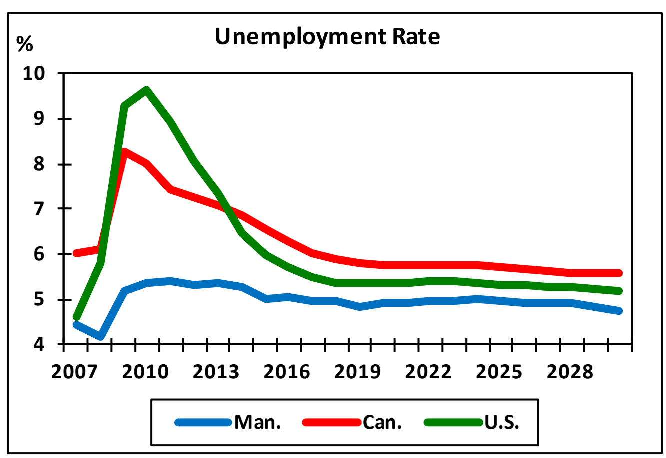
Manitoba's total employment expanded by 3,100 persons in 2013 or 0.5% relative to 2012. The primary goods producing sectors have rebounded this past year with agriculture posting gains of 3,100 persons, construction at 1,200 persons, and the forestry, utilities, and the manufacturing sectors gaining each 400 persons of employment. The services producing sector struggled this past year as employment dropped by 2,200 in the trade sector, and the finance, insurance, real estate, and public administration sectors each dropping by 1,400 persons of employment. In 2013 Manitoba's unemployment rate increased from 5.3% to 5.4% but remains the third lowest of the Canadian provinces after Alberta and Saskatchewan and below the 7.1% national average.

	Manitoba			Canada			United States		
	2003	**2013**	**% chge 13/12**	**2003**	**2013**	**% chge 13/12**	**2003**	**2013**	**% chge 13/12**
Population 15+ – '000s	875	974	1.1	25,099	28,673	1.3	221,168	245,679	1.0
Participation Rate - %	68.7	68.7		67.5	66.5		66.2	63.2	
Labour Force – '000s	601	669	0.5	16,948	19,079	1.1	146,500	155,389	0.3
Employment – '000s	571	633	0.5	15,663	17,731	1.3	137,729	143,929	1.0
Unemployment Rate – %	5.0	5.4		7.6	7.1		6.0	7.4	
Employment Rate – %	65.2	65.0		62.4	61.8		62.3	58.6	

OUTLOOK:

Manitoba's employment is forecast to grow by 1.2% in 2014 – up from 0.5% in 2013. Employment growth is expected to increase over most of the medium term to average 2.0% per year over the period. This is in line with overall economic growth averaging 2.5% annually and productivity gains averaging 1.0% per year over the medium outlook. Over the 2014-2035 period, Manitoba's and Canada's employment levels are forecast to grow annually at 0.8% and 0.7% respectively, while the United States' is anticipated to grow at 1% annually. Manitoba's unemployment rate is expected to trend downwards from 5.3% in 2014 to 5.0% in 2019 and remain around 4.9% until 2035. Canada's unemployment rate is expected to trend from 6.9% in 2014 to 5.7% in 2035. The United States' unemployment rate is expected to trend from 6.5% in 2014 to 5.1% in 2035.





HOUSING

RECENT PERFORMANCE:

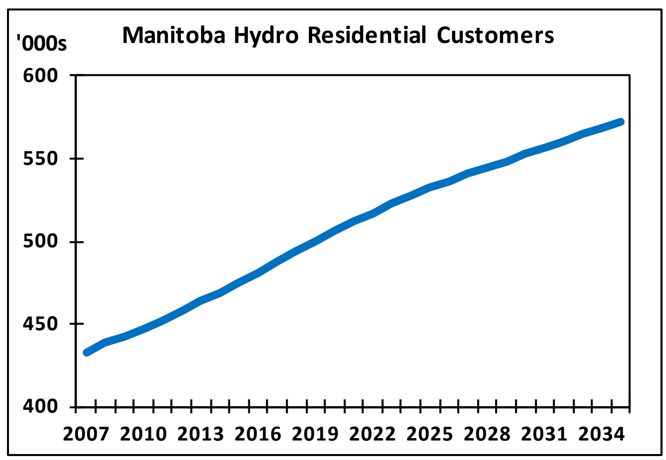
Total Manitoba's housing starts were 7,465 in 2013, up from 7,242 units in 2012. Population growth, increase in employment numbers, rising wages, and low mortgage rates were the driving force behind the demand for housing in 2013. With respect to Manitoba Hydro metered residential customers, there was an increase of 6,387 units in 2013 relative to 2012.

OUTLOOK:

Due to reduced in-migration in the short term, EO2014 forecasts that Manitoba housing starts are expected to remain stable over the next two years before it picks up in 2016. In the medium to long run, housing starts are expected to fall as population growth stabilizes due to reduced migration. EO2014 forecasts that Manitoba housing starts will increase at approximately 6,940 units annually in the longer term. The forecasted annual population growth rate in Manitoba of 13,400 people in EO2014 is 1,500 people lower than the growth rate forecast in EO2013 and is the main driver in the increased housing starts.

EO2014 forecasts that Manitoba residential customers will increase by 4,920 units or 0.9% annually over the 2014-2035 period, down about 430 units annually from EO2013. Refer to Appendices A and B for the forecasts of Manitoba residential customers expressed in calendar and fiscal years.

	Man. Housing Starts	Man. Res. Cust. '000s	Can. Housing Starts '000s
1995	1,963	398	111
1996	2,318	400	125
1997	2,612	403	147
1998	2,895	405	137
1999	3,133	408	150
2000	2,560	410	152
2001	2,963	412	163
2002	3,617	415	205
2003	4,206	418	218
2004	4,440	421	233
2005	4,731	425	225
2006	5,028	429	227
2007	5,738	433	228
2008	5,537	439	211
2009	4,174	443	149
2010	5,888	447	190
2011	6,083	452	194
2012	7,242	458	215
2013	7,465	464	188



INTEREST RATES

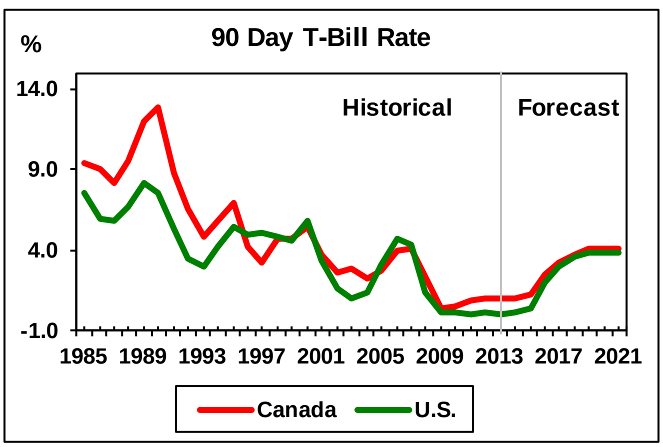
RECENT PERFORMANCE:

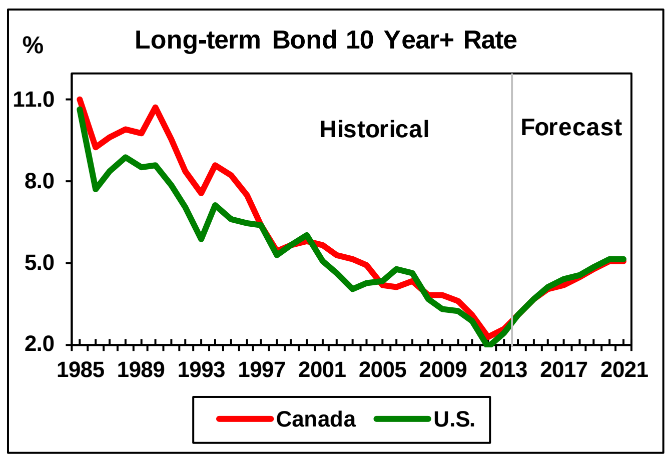
For the purposes of representing the long-term interest rates that impact Manitoba Hydro, for Canadian long-term debt the average of a 10 year and a 30 year Canadian long bond rate is used and is referred to as a 10 Yr+ rate. For U.S. long-term debt, a 10 year U.S. long bond rate is used.

In 2013, the Bank of Canada kept the overnight policy rate unchanged at 1.00% throughout 2013. The 90 Day T-bill rate remained unchanged at 0.96% in 2013 similar to 0.96% in 2012, while the 10 Yr+ bond rate increased from 2.25% in 2012 to 2.58% over the same period.

OUTLOOK:

The consensus survey expects the Bank of Canada's next move is to start to increase interest rates in the short term. The Federal Reserve is expected to move with the Bank of Canada, narrowing the gap between Canada/U.S. interest rate spreads and is expected to decline over the forecast period. Economic Outlook 2014 forecast short and long-term rates will gradually rise over the last half of the forecast period, reflecting the Bank of Canada's concern on inflation impact. Economic Outlook 2014 forecasts Canadian 90 Day T-Bill rates are expected to trend from 0.95% in 2014 to 4.05% in the long term. Canada and U.S. long bond rates are forecast to trend up to 5.00% and 5.10%, respectively.





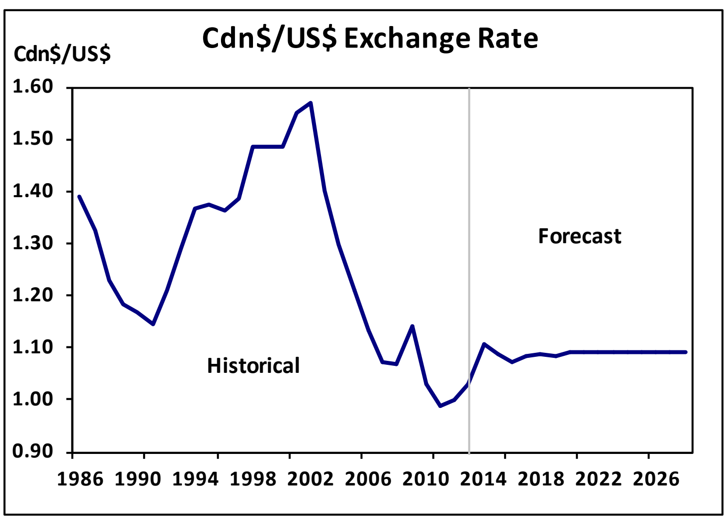
EXCHANGE RATE

RECENT PERFORMANCE:

In 2013 the Canadian dollar depreciated relative to the U.S. dollar by 3.1% relative to 2012. The recent decline of the Canada-U.S. dollar has been associated with softening commodity prices and the worsening current account balance. Renewed confidence in the U.S. currency and an underperforming Canadian economy relative to the U.S. are also responsible for the loonie's depreciation.

OUTLOOK:

Economic Outlook 2014 forecasts that the Canadian dollar is expected to remain low for the rest of the year and into the near term with a slight appreciation of a few cents. As the Bank of Canada will likely increase interest rates in 2015 this will pressure the Canadian dollar to increase, however, this change won't be very significant as the survey suggests the Federal Reserve to also move rates at similar times. Accordingly, narrowing Canada/U.S. interest rates will keep the dollar low and well below parity.



Year	US$/ Cdn.$	Cdn.$/ US$
1970	0.96	1.04
1975	0.98	1.02
1980	0.86	1.17
1985	0.73	1.37
1990	0.86	1.17
1995	0.73	1.37
1996	0.73	1.36
1997	0.72	1.38
1998	0.67	1.48
1999	0.67	1.49
2000	0.65	1.49
2001	0.64	1.55
2002	0.71	1.57
2003	0.77	1.40
2004	0.83	1.30
2005	0.88	1.21
2006	0.93	1.13
2007	0.94	1.07
2008	0.94	1.07
2009	0.88	1.14
2010	0.97	1.03
2011	1.01	0.99
2012	1.00	1.00
2013	0.97	1.03
2025	0.92	1.09
2035	0.92	1.09

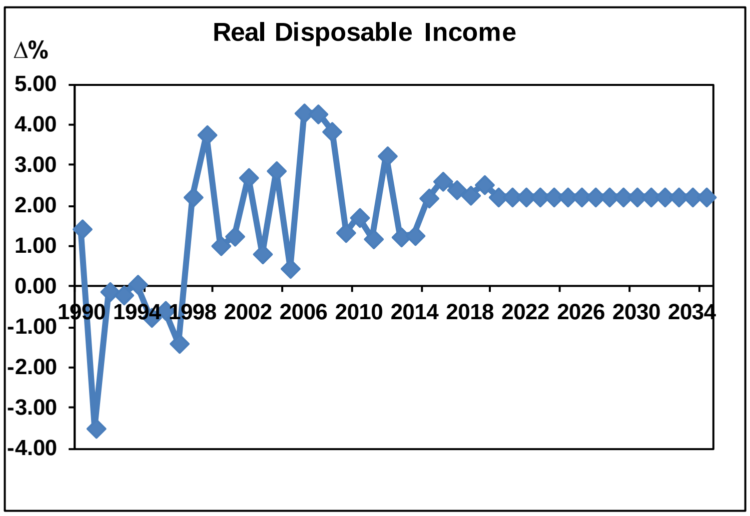
MANITOBA DISPOSABLE INCOME

RECENT PERFORMANCE:

Slowdowns in wage growth were largely attributed to austerity measures within the government and associated programs.

OUTLOOK:

Manitoba's labour market is expected to tighten in the medium term, due to anticipated expansions in the construction and mining industry, putting upward pressure on wage rates. This robust growth in the goods-producing sector will help lift employment and household disposable income over the next two years and on.



Real Disposable Income	
Year	Δ%
1990	1.43
1991	-3.50
1992	-0.12
1993	-0.20
1994	0.06
1995	-0.76
1996	-0.58
1997	-1.40
1998	2.22
1999	3.76
2000	1.02
2001	1.25
2002	2.70
2003	0.81
2004	2.87
2005	0.45
2006	4.29
2007	4.27
2008	3.84
2009	1.34
2010	1.71
2011	1.18
2012	3.24
2013	1.23
2025	2.20
2035	2.20

APPENDIX A

MANITOBA/CANADA ECONOMIC STATISTICS – FISCAL YEAR BASIS

Year	Man. Real GDP % chge	Man. CPI % chge	Man. Popu-lation '000s	Man. Residential Customers '000s	Cdn. Real GDP % chge	Cdn. CPI % chge	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 10 Yr+ Rate %	C$/ US$
1989/90	2.7	4.7	1,104	385	2.0	5.2	12.37	9.77	1.18
1990/91	1.2	5.0	1,106	387	-1.1	5.0	12.07	10.59	1.16
1991/92	-2.4	3.8	1,110	389	-1.1	4.4	8.03	9.29	1.15
1992/93	0.7	1.9	1,114	391	1.1	1.6	6.25	8.18	1.23
1993/94	1.2	2.4	1,119	394	3.1	1.5	4.46	7.39	1.31
1994/95	2.8	1.6	1,125	396	4.8	0.4	6.46	8.95	1.38
1995/96	0.9	2.5	1,130	398	1.7	2.1	6.17	7.93	1.36
1996/97	3.2	2.5	1,135	400	2.5	1.7	3.67	7.28	1.36
1997/98	4.2	1.5	1,136	404	4.6	1.4	3.63	6.06	1.40
1998/99	3.6	1.5	1,139	405	3.9	0.9	4.81	5.35	1.50
1999/00	2.1	2.2	1,144	408	5.3	2.2	4.82	5.69	1.47
2000/01	3.4	2.5	1,148	411	4.5	2.7	5.42	5.66	1.50
2001/02	1.2	2.1	1,153	413	1.5	2.2	3.09	5.91	1.57
2002/03	1.5	2.3	1,158	415	2.9	3.0	2.79	5.41	1.55
2003/04	1.5	0.9	1,166	419	1.7	1.9	2.67	4.97	1.35
2004/05	2.4	2.7	1,174	422	3.5	2.2	2.31	4.81	1.28
2005/06	3.0	2.4	1,180	426	3.3	2.3	3.02	4.17	1.19
2006/07	3.5	2.0	1,185	430	2.0	1.9	4.16	4.23	1.14
2007/08	3.1	1.9	1,191	434	2.1	2.1	3.83	4.24	1.03
2008/09	2.8	2.2	1,200	440	0.2	2.2	1.84	3.66	1.13
2009/10	0.5	0.6	1,212	444	-1.6	0.4	0.22	3.89	1.09
2010/11	2.4	1.0	1,224	448	3.5	2.0	0.78	3.48	1.02
2011/12	1.9	2.8	1,238	453	2.3	2.8	0.91	2.83	0.99
2012/13	2.5	1.6	1,254	459	1.6	1.2	0.97	2.18	1.00
2013/14	2.3	2.4	1,269	465	2.1	1.1	0.94	2.70	1.05
Forecast									
2014/15	2.2	1.8	1,283	471	2.3	1.6	1.00	3.25	1.10
2015/16	2.5	1.9	1,300	477	2.5	1.9	1.55	3.75	1.08
2016/17	2.7	2.0	1,317	483	2.6	2.0	2.70	4.05	1.07
2017/18	2.6	2.0	1,335	490	2.5	2.1	3.40	4.25	1.08
2018/19	2.1	2.0	1,352	496	2.4	2.0	3.80	4.50	1.09
2019/20	1.8	2.0	1,368	502	2.3	2.0	4.05	4.80	1.08
2020/21	1.6	2.1	1,385	508	1.9	2.0	4.05	5.00	1.09
2021/22	1.6	2.1	1,400	513	1.9	2.0	4.05	5.00	1.09
2022/23	1.6	2.1	1,414	519	1.9	2.0	4.05	5.00	1.09
2023/24	1.6	2.1	1,428	524	1.9	2.0	4.05	5.00	1.09
2024/25	1.6	2.1	1,441	529	1.9	2.0	4.05	5.00	1.09
2025/26	1.6	2.1	1,454	533	1.9	2.0	4.05	5.00	1.09
2026/27	1.6	2.1	1,466	538	1.9	2.0	4.05	5.00	1.09
2027/28	1.6	2.1	1,477	542	1.9	2.0	4.05	5.00	1.09
2028/29	1.6	2.1	1,488	546	1.9	2.0	4.05	5.00	1.09
2029/30	1.6	2.1	1,499	550	1.9	2.0	4.05	5.00	1.09
2030/31	1.6	2.1	1,510	554	1.9	2.0	4.05	5.00	1.09
2031/32	1.6	2.1	1,521	558	1.9	2.0	4.05	5.00	1.09
2032/33	1.6	2.1	1,531	562	1.9	2.0	4.05	5.00	1.09
2033/34	1.6	2.1	1,542	566	1.9	2.0	4.05	5.00	1.09
2034/35	1.6	2.1	1,553	569	1.9	2.0	4.05	5.00	1.09

APPENDIX B

MANITOBA/CANADA ECONOMIC STATISTICS – CALENDAR YEAR BASIS

Year	Man. Real GDP % chge	Man. CPI % chge	Man. Popu-lation '000s	Man. Residential Customers '000s	Cdn. Real GDP % chge	Cdn. CPI % chge	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 10 Yr+ Rate %	C$/ US$
1989	2.7	4.7	1,104	385	2.4	5.1	12.05	9.73	1.18
1990	2.7	4.5	1,105	387	0.1	4.8	12.81	10.73	1.17
1991	-3.4	5.1	1,110	389	-2.1	5.6	8.73	9.57	1.15
1992	0.8	1.4	1,113	391	0.9	1.4	6.58	8.37	1.21
1993	0.4	2.7	1,118	394	2.6	1.9	4.84	7.54	1.29
1994	3.6	1.4	1,123	396	4.6	0.1	5.78	8.56	1.37
1995	0.3	2.7	1,129	398	2.7	2.2	6.89	8.24	1.37
1996	3.0	2.2	1,134	400	1.7	1.5	4.21	7.48	1.36
1997	4.1	2.0	1,136	403	4.3	1.7	3.26	6.39	1.38
1998	4.4	1.3	1,137	405	4.1	1.0	4.73	5.44	1.48
1999	1.4	2.0	1,142	408	5.0	1.8	4.72	5.64	1.49
2000	4.3	2.5	1,147	410	5.1	2.7	5.49	5.80	1.49
2001	1.0	2.7	1,151	412	1.7	2.5	3.77	5.63	1.55
2002	1.6	1.5	1,157	415	2.8	2.2	2.59	5.25	1.57
2003	1.3	1.8	1,164	418	1.9	2.8	2.87	5.09	1.40
2004	2.3	2.0	1,173	421	3.1	1.8	2.22	4.87	1.30
2005	2.7	2.7	1,178	425	3.2	2.2	2.73	4.16	1.21
2006	3.7	2.0	1,184	429	2.6	2.0	4.03	4.13	1.13
2007	2.9	2.0	1,189	433	2.0	2.2	4.15	4.29	1.07
2008	3.8	2.3	1,198	439	1.2	2.3	2.39	3.84	1.07
2009	-0.2	0.6	1,209	443	-2.7	0.3	0.35	3.77	1.14
2010	2.6	0.8	1,221	447	3.4	1.8	0.56	3.55	1.03
2011	1.7	3.0	1,234	452	2.5	2.9	0.93	3.09	0.99
2012	2.6	1.6	1,250	458	1.7	1.5	0.96	2.25	1.00
2013	2.4	2.2	1,265	464	2.0	0.9	0.96	2.58	1.03
Forecast									
2014	2.1	1.8	1,279	469	2.3	1.5	0.95	3.05	1.11
2015	2.4	1.9	1,295	475	2.5	1.9	1.30	3.65	1.09
2016	2.7	1.9	1,313	481	2.6	2.0	2.50	4.00	1.07
2017	2.7	2.0	1,330	488	2.5	2.1	3.25	4.20	1.08
2018	2.2	2.0	1,347	494	2.4	2.0	3.70	4.45	1.09
2019	1.8	2.0	1,364	500	2.4	2.0	4.05	4.75	1.08
2020	1.6	2.1	1,381	506	1.9	2.0	4.05	5.00	1.09
2021	1.6	2.1	1,396	512	1.9	2.0	4.05	5.00	1.09
2022	1.6	2.1	1,411	517	1.9	2.0	4.05	5.00	1.09
2023	1.6	2.1	1,425	523	1.9	2.0	4.05	5.00	1.09
2024	1.6	2.1	1,438	527	1.9	2.0	4.05	5.00	1.09
2025	1.6	2.1	1,451	532	1.9	2.0	4.05	5.00	1.09
2026	1.6	2.1	1,463	537	1.9	2.0	4.05	5.00	1.09
2027	1.6	2.1	1,475	541	1.9	2.0	4.05	5.00	1.09
2028	1.6	2.1	1,486	545	1.9	2.0	4.05	5.00	1.09
2029	1.6	2.1	1,497	549	1.9	2.0	4.05	5.00	1.09
2030	1.6	2.1	1,507	553	1.9	2.0	4.05	5.00	1.09
2031	1.6	2.1	1,518	557	1.9	2.0	4.05	5.00	1.09
2032	1.6	2.1	1,529	561	1.9	2.0	4.05	5.00	1.09
2033	1.6	2.1	1,539	565	1.9	2.0	4.05	5.00	1.09
2034	1.6	2.1	1,550	568	1.9	2.0	4.05	5.00	1.09
2035	1.6	2.1	1,560	572	1.9	2.0	4.05	5.00	1.09

Economic Outlook Appendix A - Fall 2014 Update

MANITOBA / CANADA ECONOMIC STATISTICS - FISCAL YEAR BASIS

Year	Man. Real GDP % chge	Man. CPI % chge	Man. Popu- lation '000s	Man. Residential Customers '000s	Cdn. Real GDP % chge	Cdn. CPI % chge	Cdn 90 Day T-Bill Rate %	Cdn LT Bond 10 Yr+ Rate %	C$/ US$
1989/90	2.7	4.7	1,104	385	2.0	5.2	12.37	9.77	1.18
1990/91	1.2	5.0	1,106	387	-1.1	5.0	12.07	10.59	1.16
1991/92	-2.4	3.8	1,110	389	-1.1	4.4	8.03	9.29	1.15
1992/93	0.7	1.9	1,114	391	1.1	1.6	6.25	8.18	1.23
1993/94	1.2	2.4	1,119	394	3.1	1.5	4.46	7.39	1.31
1994/95	2.8	1.6	1,125	396	4.8	0.4	6.46	8.95	1.38
1995/96	0.9	2.5	1,130	398	1.7	2.1	6.17	7.93	1.36
1996/97	3.2	2.5	1,135	400	2.5	1.7	3.67	7.28	1.36
1997/98	4.2	1.5	1,136	404	4.6	1.4	3.63	6.06	1.40
1998/99	3.6	1.5	1,139	405	3.9	0.9	4.81	5.35	1.50
1999/00	2.1	2.2	1,144	408	5.3	2.2	4.82	5.69	1.47
2000/01	3.4	2.5	1,148	411	4.5	2.7	5.42	5.66	1.50
2001/02	1.2	2.1	1,153	413	1.5	2.2	3.09	5.91	1.57
2002/03	1.5	2.3	1,158	415	2.9	3.0	2.79	5.41	1.55
2003/04	1.5	0.9	1,166	419	1.7	1.9	2.67	4.97	1.35
2004/05	2.4	2.7	1,174	422	3.5	2.2	2.31	4.81	1.28
2005/06	3.0	2.4	1,180	426	3.3	2.3	3.02	4.17	1.19
2006/07	3.5	2.0	1,185	430	2.0	1.9	4.16	4.23	1.14
2007/08	3.1	1.9	1,191	434	2.1	2.1	3.83	4.24	1.03
2008/09	2.8	2.2	1,200	440	0.2	2.2	1.84	3.66	1.13
2009/10	0.5	0.6	1,212	444	-1.6	0.4	0.22	3.89	1.09
2010/11	2.4	1.0	1,224	448	3.5	2.0	0.78	3.48	1.02
2011/12	1.9	2.8	1,238	453	2.3	2.8	0.91	2.83	0.99
2012/13	2.5	1.6	1,254	459	1.6	1.2	0.97	2.18	1.00
2013/14	2.2	2.4	1,269	465	2.2	1.1	0.94	2.70	1.05
Forecast									
2014/15	2.2	1.8	1,283	471	2.3	1.6	0.95	2.60	1.10
2015/16	2.5	1.9	1,300	477	2.5	1.9	1.30	3.30	1.12
2016/17	2.7	2.0	1,317	483	2.6	2.0	2.40	3.75	1.12
2017/18	2.6	2.0	1,335	490	2.5	2.1	3.10	4.05	1.12
2018/19	2.1	2.0	1,352	496	2.4	2.0	3.45	4.25	1.12
2019/20	1.8	2.0	1,368	502	2.3	2.0	3.90	4.45	1.10
2020/21	1.6	2.1	1,385	508	1.9	2.0	3.90	4.45	1.10
2021/22	1.6	2.1	1,400	513	1.9	2.0	3.90	4.45	1.10
2022/23	1.6	2.1	1,414	519	1.9	2.0	3.90	4.45	1.10
2023/24	1.6	2.1	1,428	524	1.9	2.0	3.90	4.45	1.10
2024/25	1.6	2.1	1,441	529	1.9	2.0	3.90	4.45	1.10
2025/26	1.6	2.1	1,454	533	1.9	2.0	3.90	4.45	1.10
2026/27	1.6	2.1	1,466	538	1.9	2.0	3.90	4.45	1.10
2027/28	1.6	2.1	1,477	542	1.9	2.0	3.90	4.45	1.10
2028/29	1.6	2.1	1,488	546	1.9	2.0	3.90	4.45	1.10
2029/30	1.6	2.1	1,499	550	1.9	2.0	3.90	4.45	1.10
2030/31	1.6	2.1	1,510	554	1.9	2.0	3.90	4.45	1.10
2031/32	1.6	2.1	1,521	558	1.9	2.0	3.90	4.45	1.10
2032/33	1.6	2.1	1,531	562	1.9	2.0	3.90	4.45	1.10
2033/34	1.6	2.1	1,542	566	1.9	2.0	3.90	4.45	1.10
2034/35	1.6	2.1	1,553	569	1.9	2.0	3.90	4.45	1.10

APPENDIX 3.2: ADDITIONAL INFORMATION FOR INTEREST RATE FORECAST

Table 1 on the following page depicts the sources used to derive the forecast of Canadian 3 month T-bill rates for each quarter of the 2014/15 – 2020/21 period (with end of period rates adjusted to a comparable average period basis), as utilized in IFF14.

Table 2 depicts the sources used to derive the forecast of Canadian bond yield 10 yr+ rates for the 2014/15 – 2020/21 period (with end of period rates adjusted to a comparable average period basis), as utilized in IFF14.

Copies of the publically available source forecasts utilized in IFF14 are provided at the end of this response.

For forecasters that provided end of period rates, the rates provided in Tables 1 and 2 reflect rates adjusted to a comparable average period basis. For example, Desjardin's forecast provided end of period rates. Their forecast for 2015 Q2 end of period is 1.00% and 2015 Q3 end of period is 1.20% for Canada 3-month T-Bill. In order to place the forecast on an equivalent basis for a 2015 Q3 average period forecast, Desjardin's 2015 Q3 end of period forecast of 1.20% was averaged with their 2015 Q2 end of period forecast of 1.00% to approximate an average period 2015 Q3 forecast of 1.10%. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates.

Table 1 – Canadian 3-Month T-Bill Rate - %

		End Period	2014			2015				2016				2017				2018				2019				2020				2021
	Fcst Date	or Average	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO Nesbitt Burns	19-Sep-14	Average	0.93	0.93	0.93	0.93	0.93	0.93	1.19	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
CIBC	18-Sep-14	End Period	0.93	0.93	0.93	0.98	1.03	1.13	1.33	1.45	1.45	1.43	1.43	1.90	1.90	1.90	1.90	2.70	2.70	2.70	2.70									
Desjardins	29-Sep-14	End Period	0.93	0.93	0.95	1.00	1.00	1.10	1.35																					
Laurentian	5-Sep-14	End Period	0.93	0.93	0.95	1.00	1.00	1.00	1.25																					
National Bank	1-Oct-14	End Period	0.93	0.93	0.93	1.00	1.25	1.69	1.93																					
Royal Bank	1-Sep-14	End Period	0.93	0.93	1.00	1.10	1.23	1.48	1.73																					
Scotiabank	1-Oct-14	End Period	0.93	0.93	0.95	1.00	1.03	1.13	1.38																					
TD Bank	25-Sep-14	End Period	0.93	0.93	0.93	0.95	1.00	1.23	1.40	1.48	1.70	1.90	2.00	2.28	2.63	2.85	2.95	2.95	2.95	2.95	2.95									
IHS Global Insight	10-Sep-14	Average	0.93	0.93	0.97	1.00	1.00	1.08	1.40	2.17	2.59	3.07	3.54	4.12	4.51	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.50
Conference Board	19-Sep-14	Average	0.93	0.93	0.94	0.96	1.00	1.13	1.21	1.25	1.42	1.67	1.92	2.17	2.42	2.67	2.92	3.17	3.42	3.63	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
			2014/15				2015/16				2016/17				2017/18				2018/19				2019/20				2020/21 & on			
EO2014 Fall Update - Fiscal			0.95				1.30				2.40				3.10				3.45				3.90				3.90			

Note: The rates provided for Q2 and Q3 reflect actual average period Canadian 3-month T-bill rates.

Note: In the case where source forecasts are provided as end-of-period, the 2014 Q3 end-of-period actual rate of 0.91% was averaged with the source forecasters' end-of-period rate for Q4 in order to approximate an average period 2014 Q4 forecast rate.

Note: The extended forecast provided by BMO Nesbitt Burns for 2016+ is proprietary and cannot be disclosed.

Table 2 – Canadian 10 Year+ Bond Yield Rate - %

		End Period	2014			2015				2016				2017				2018				2019				2020				2021
	Fcst Date	or Average	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO Nesbitt Burns	19-Sep-14	Average	2.61	2.44	2.69	2.90	3.07	3.26	3.42	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
CIBC	18-Sep-14	End Period	2.61	2.44	2.45	2.76	3.15	3.28	3.19	3.04	2.98	2.98	3.04	3.25	3.25	3.25	3.25	3.55	3.55	3.55	3.55									
Desjardins	29-Sep-14	End Period	2.61	2.44	2.60	2.91	3.14	3.28	3.36																					
Laurentian	5-Sep-14	End Period	2.61	2.44	2.48	2.61	2.81	3.06	3.35																					
National Bank	1-Oct-14	End Period	2.61	2.44	2.52	2.68	2.95	3.20	3.36																					
Royal Bank	1-Sep-14	End Period	2.61	2.44	2.64	2.94	3.11	3.31	3.56																					
Scotiabank	1-Oct-14	End Period	2.61	2.44	2.55	2.76	3.06	3.34	3.46																					
TD Bank	25-Sep-14	End Period	2.61	2.44	2.53	2.74	2.95	3.15	3.34	3.50	3.64	3.74	3.83																	
IHS Global Insight	10-Sep-14	Average	2.61	2.44	2.87	3.22	3.49	3.57	3.64	3.79	3.89	4.01	4.15	4.37	4.44	4.43	4.43	4.43	4.43	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.41	4.41
Conference Board	19-Sep-14	Average	2.61	2.44	2.29	2.88	2.89	3.08	3.23	3.37	3.51	3.65	3.80	3.95	4.09	4.22	4.35	4.46	4.58	4.69	4.86	4.86	4.86	4.86	4.86	4.87	4.87	4.87	4.87	4.87
			2014/15				2015/16				2016/17				2017/18				2018/19				2019/20				2020/21 & on			
EO2014 Fall Update - Fiscal			2.60				3.30				3.75				4.05				4.25				4.45				4.45			

Note: The rates provided for Q2 and Q3 reflect actual average period Canadian 10 Year+ Bond Yield rates.

Note: In the case where source forecasts are provided as end-of-period, the 2014 Q3 end-of-period actual rate of 2.43% (average of 2.19% for Canada 10 year and 2.67% for Canada 30 year) was averaged with the source forecasters' end-of-period rate for Q4 in order to approximate an average period 2014 Q4 forecast rate.

Note: The extended forecast provided by BMO Nesbitt Burns for 2016+ is proprietary and cannot be disclosed.

The calculations of the Canadian 3-Month T-Bill and Canada Bond Yield 10 year+ rates for the 2014/15, 2015/16 and 2016/17 period are as follows:

- The 2014/15 forecast included the average of all data points within Q2, Q3, Q4 of 2014 and Q1 of 2015. The 2015/16 forecast included the average of all data points within Q2, Q3, Q4 of 2015 and Q1 of 2016. The 2016/17 forecast included the average of all data points within Q2, Q3, Q4 of 2016 and Q1 of 2017. For example, the Canada 3-Month T-Bill rate for 2015/16 of 1.30% (rounded to the nearest 5 basis points) in Table 1 was calculated as the average of the following data points:

	2015 Q2	**2015 Q3**	**2015 Q4**	**2016 Q1**
BMO Nesbitt Burns	0.93%	0.93%	1.19%	*
CIBC	1.03%	1.13%	1.33%	1.45%
Desjardins	1.00%	1.10%	1.35%	
Laurantian	1.00%	1.00%	1.25%	
National Bank	1.25%	1.69%	1.93%	
Royal Bank	1.23%	1.48%	1.73%	
Scotiabank	1.03%	1.13%	1.38%	
TD Bank	1.00%	1.23%	1.40%	1.48%
IHS Global Insight	1.00%	1.08%	1.40%	2.17%
Conference Board	1.00%	1.13%	1.21%	1.25%
Average	**1.30%**			

**Information provided by BMO is proprietary and cannot be disclosed.*

The Manitoba Hydro Canadian short-term interest rate was calculated by adding the guarantee fee of 1.00% to the 3-Month T-Bill rate as follows:

	Canada 3-Month T-Bill	Guarantee Fee	MH Cdn Short Term Rate
2014/15	0.95%	1.00%	1.95%
2015/16	1.30%	1.00%	2.30%
2016/17	2.40%	1.00%	3.40%

The Manitoba Hydro Canadian long-term interest rate was calculated by adding the appropriate credit spread to the Canada Bond Yield 10 Year+ rate and a provincial debt guarantee fee as follows:

	Canada Bond Yield 10 Yr+	Spread	Guarantee Fee	MH Cdn Long Term Rate
2014/15	2.60%	0.90%	1.00%	4.50%
2015/16	3.30%	0.80%	1.00%	5.10%
2016/17	3.75%	0.75%	1.00%	5.50%

Canadian Economic Outlook

Appendix 3.2 - Attachment

BMO Capital Markets Economics

September 19, 2014

				2013				2014				2015	2012	2013	2014	2015
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4				
PRODUCTION	**(quarter/quarter % change : a.r.)**															
Real GDP (chain-weighted)	3.0	1.9	3.0	2.7	0.9	3.1	3.0	2.0	2.5	2.5	2.7	2.6	1.7	2.0	2.3	2.5
Final Sales	1.2	2.6	2.4	1.6	1.4	4.7	3.1	2.1	2.5	2.6	2.8	2.7	1.7	1.8	2.5	2.7
Final Domestic Demand	0.4	2.0	1.8	0.8	-0.2	3.0	1.5	1.5	2.0	2.0	2.0	1.9	2.3	1.4	1.3	1.9
Consumer Spending	1.4	3.8	3.0	2.4	1.7	3.8	2.0	1.9	2.2	2.3	2.2	2.0	1.9	2.4	2.6	2.2
Durables	2.2	14.0	0.3	-3.7	1.6	14.7	2.5	0.0	1.8	2.0	2.0	1.5	2.6	3.4	3.5	2.3
Non-Durables	-0.3	2.1	4.9	5.5	4.4	-0.6	2.0	2.2	2.2	2.1	2.2	2.0	0.7	2.4	3.1	2.0
Services	1.9	2.7	1.9	1.9	1.4	2.8	2.0	2.2	2.3	2.4	2.3	2.2	2.2	2.1	2.0	2.3
Government Spending	-0.3	-0.2	-0.4	-1.2	-0.8	1.1	0.9	1.0	1.3	1.1	1.1	1.1	1.0	0.3	-0.1	1.1
Business Investment	0.9	-1.2	0.5	-0.8	-3.0	0.9	1.9	2.8	3.8	4.3	3.7	4.2	6.2	1.3	-0.3	3.3
Non-Residential Construction	2.5	-1.0	3.1	-2.4	-0.7	0.6	1.5	2.0	3.0	4.5	4.0	4.5	6.9	2.2	0.1	3.0
Machinery and Equipment	-1.6	-1.6	-3.4	1.7	-6.6	1.5	2.5	4.0	5.0	4.0	3.5	4.0	5.2	-0.2	-1.1	3.8
Residential Construction	-4.5	6.1	0.4	-1.7	-5.6	11.9	1.0	0.0	0.0	0.0	0.7	0.7	6.1	-0.3	0.9	1.0
Exports	5.4	4.9	0.7	3.9	-0.7	17.8	8.5	4.3	5.0	5.3	5.4	5.5	1.5	2.2	5.4	6.2
Imports	2.7	2.4	-0.7	1.5	-5.5	11.1	3.4	2.5	3.3	3.6	4.0	3.9	3.1	1.1	1.5	3.8
	(billions of chained 2007 dollars : a.r.)															
Inventory Change	11.8	7.7	11.5	16.8	14.5	7.1	6.9	6.5	6.4	6.1	5.8	5.5	6.8	11.9	8.7	5.9
Contribution to GDP Growth	2.0	-1.0	1.0	1.4	-0.6	-1.8	-0.0	-0.1	-0.0	-0.1	-0.1	-0.1	-0.0	0.2	-0.2	-0.2
Net Exports	-44.0	-41.1	-39.2	-36.4	-29.5	-22.4	-15.9	-13.5	-11.3	-9.0	-7.2	-5.0	-45.1	-40.2	-20.3	-8.1
Contribution to GDP Growth	0.7	0.7	0.4	0.7	1.5	2.0	1.6	0.6	0.5	0.6	0.8	0.9	-0.5	0.3	1.2	0.8
	(billions of dollars : a.r.)															
Nominal GDP	1,863	1,866	1,890	1,906	1,937	1,956	1,979	1,996	2,018	2,041	2,064	2,087	1,820	1,881	1,967	2,052
(% chng : a.r.)	6.0	0.5	5.4	3.3	6.7	4.1	4.6	3.6	4.5	4.5	4.5	4.6	3.4	3.4	4.6	4.3
INFLATION	**(quarter/quarter % change : a.r.)**															
GDP Price Index	2.9	-1.4	2.6	0.4	5.9	0.7	1.6	1.6	2.0	2.0	1.8	1.9	1.7	1.3	2.2	1.8
CPI All Items	1.6	-0.1	1.9	0.5	2.8	3.7	1.3	1.6	2.0	2.1	2.1	2.1	1.5	0.9	2.0	2.0
Excl. Food & Energy	1.3	0.9	0.9	0.3	2.4	2.3	2.5	1.8	1.9	2.0	2.0	2.0	1.3	0.9	1.7	2.0
Food Prices	1.2	0.8	0.8	0.9	2.2	5.5	1.1	1.5	2.2	2.3	2.0	2.6	2.4	1.2	2.1	2.1
Energy Prices	3.1	-3.8	10.7	-2.6	10.7	13.4	-5.2	-0.9	2.3	2.3	2.4	2.4	1.7	1.5	4.9	1.4
Services	0.6	2.4	2.6	0.5	1.6	3.6	3.4	2.0	1.8	2.1	2.0	2.2	2.0	1.4	2.2	2.3
	(year/year % change)															
CPI All Items	0.9	0.8	1.1	0.9	1.4	2.2	2.1	2.3	2.1	1.7	1.9	2.1				
BoC Core	1.3	1.2	1.3	1.2	1.3	1.7	2.0	2.2	2.1	1.9	1.8	1.9	1.7	1.2	1.8	1.9
FINANCIAL	**(average for the quarter : %)**															
Overnight Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.00	1.00	1.00	1.06
3-Month T-Bill	0.95	1.00	1.00	0.93	0.87	0.93	0.94	0.93	0.93	0.93	0.93	1.19	0.94	0.97	0.92	1.00
90-Day BAs	1.20	1.18	1.18	1.23	1.26	1.27	1.28	1.28	1.28	1.28	1.28	1.52	1.21	1.20	1.27	1.34
10 Year Bond Yield	1.92	1.96	2.58	2.58	2.47	2.35	2.14	2.42	2.65	2.83	3.02	3.19	1.87	2.26	2.35	2.92
Canada/US spread: (bps)																
90 day	86	95	96	87	82	90	92	91	91	76	49	52	85	91	89	67
10 year	-4	-3	-13	-16	-30	-27	-35	-35	-33	-30	-27	-25	7	-9	-32	-29
FOREIGN TRADE	**(billions of dollars : a.r.)**															
Current Account Balance	-60.3	-61.5	-56.8	-62.6	-48.1	-47.5	-39.2	-37.2	-34.3	-31.8	-29.5	-26.4	-62.2	-60.3	-43.0	-30.5
(% of GDP)	-3.2	-3.3	-3.0	-3.3	-2.5	-2.4	-2.0	-1.9	-1.7	-1.6	-1.4	-1.3	-3.4	-3.2	-2.2	-1.5
Merchandise Balance	-6.7	-7.8	-5.7	-9.0	7.1	6.6	14.7	15.5	17.5	19.8	21.9	24.7	-12.0	-7.3	11.0	21.0
Non-Merchandise Balance	-53.6	-53.7	-51.1	-53.6	-55.2	-54.1	-53.9	-52.7	-51.8	-51.5	-51.4	-51.2	-50.2	-53.0	-54.0	-51.5
	(average for the quarter)															
Exchange Rate (US¢/C$)	99.1	97.7	96.3	95.3	90.6	91.7	92.0	91.1	90.1	88.9	87.7	87.0	100.1	97.1	91.4	88.4
Exchange Rate (C$/US$)	1.009	1.023	1.038	1.049	1.103	1.090	1.087	1.098	1.110	1.125	1.140	1.150	0.999	1.030	1.095	1.131
Exchange Rate (¥/C$)	91.5	96.4	95.2	95.7	93.1	93.6	95.7	99.4	99.9	99.6	99.4	99.6	79.9	94.7	95.5	99.6
Exchange Rate (C$/Euro)	1.33	1.34	1.38	1.43	1.51	1.50	1.44	1.43	1.46	1.47	1.47	1.46	1.29	1.37	1.47	1.46
INCOMES	**(year/year % change)**															
Corporate Profits Before Tax	-7.9	-6.9	5.6	9.4	13.0	23.3	13.6	13.0	4.0	4.9	5.1	5.6	-8.2	-0.3	15.6	4.9
Corporate Profits After Tax	6.5	2.9	12.4	8.4	3.7	9.4	6.4	7.1	4.7	4.3	3.3	14.0	1.5	7.5	6.6	6.6
Personal Income	4.3	3.5	3.3	3.4	3.3	3.7	4.2	4.0	4.2	4.7	4.6	4.7	4.3	3.6	3.8	4.5
Real Disposable Income	3.2	2.5	1.9	2.0	1.8	1.6	2.2	1.7	1.7	2.2	2.0	2.0	2.5	2.4	1.8	2.0
	(average for the quarter : %)															
Savings Rate	5.9	4.9	4.4	4.8	5.0	3.9	4.1	4.2	4.2	4.0	4.0	4.0	5.0	5.0	4.3	4.1
OTHER INDICATORS	**(quarter average)**															
Unemployment Rate (%)	7.1	7.1	7.1	7.0	7.0	7.0	7.0	6.9	6.9	6.8	6.7	6.6	7.3	7.1	7.0	6.7
Housing Starts (000s, a.r.)	172	190	194	194	175	196	197	193	189	186	184	181	215	188	190	185
Existing Home Sales (y/y % ch)	-10.1	-3.2	9.6	8.3	1.3	6.0	4.7	3.9	7.3	-1.5	-4.4	-0.7	-1.2	0.8	4.0	0.0
MLS Home Price Index (y/y % ch)	2.4	2.1	2.8	4.0	5.0	5.1	5.3	4.3	2.9	1.8	1.8	1.6	4.1	2.8	5.0	2.0
Motor Vehicle Sales (mlns, a.r.)	1.73	1.78	1.80	1.79	1.74	1.84	1.91	1.81	1.79	1.78	1.77	1.77	1.72	1.77	1.82	1.78
	(quarter/quarter % change : a.r.)															
Employment Growth	0.9	1.2	0.8	0.9	0.4	0.3	1.0	0.9	1.2	1.0	0.9	1.0	1.2	1.3	0.7	1.0
Industrial Production	7.8	-2.9	3.7	6.9	4.8	3.5	4.5	2.4	2.4	2.6	2.6	2.5	0.9	1.8	4.1	2.8
Federal Budget Balance (% of FY GDP)													-1.0	-0.9	-0.1	0.3

Note: Outlined areas represent forecast periods

Quarterly Medium Term Outlook

BMO Capital Markets *

	Forecast Date	2013				2014				2015				Long-Run Assumptions			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Cdn 90 Day T-bill - %	18-Sep-14							0.95	0.95	0.95	0.95	0.95	1.20	^			
Cdn 10 Yr Bond Yield - %	18-Sep-14							2.15	2.40	2.65	2.85	3.00	3.20	^			
Cdn 30 Yr Bond Yield - %	18-Sep-14							2.70	2.95	3.15	3.30	3.50	3.65	^			
US 90 day T-bill - %	18-Sep-14							0.02	0.02	0.02	0.20	0.45	0.65	^			
US 10 Yr Bond Yield - %	18-Sep-14							2.50	2.75	3.00	3.15	3.30	3.45	^			
US 30 Yr Bond Yield - %	18-Sep-14							3.25	3.50	3.65	3.80	3.90	4.05	^			
Exchange Rate**	18-Sep-14							1.09	1.10	1.11	1.13	1.14	1.15	^			
Cdn CPI*** - % change	18-Sep-14							2.10	2.30	2.10	1.70	1.90	2.10	^			
Cdn GDP Price Index - % change	18-Sep-14							1.60	1.60	2.00	2.00	1.80	1.90	^			
US CPI*** - % change	18-Sep-14							1.80	1.90	2.00	1.80	2.00	2.10	^			
US GDP Price Index - % change	18-Sep-14							1.00	1.50	2.10	2.10	1.80	2.00	^			

apaspaporn:
BMO provides annual granularity for CPI & GDP beyond 2015 only. It is assumed to be the same for each quarter.

breitz01:
Annualized Q/Q % change

breitz01:
Annualized Q/Q % change

* Average Period Data
** (C$/US$)
*** CPI All Items (year/year % change)
**** shaded area denotes forecast period
^ proprietary and cannot be disclosed

Quarterly Medium Term Outlook

CIBC World Markets *

			2014	2015				2016				2017	2018
		Forecast Date	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4		
Cdn 98 Day T-bill	quarterly end-of-period - %	**18-Sep-14**	0.95	1.00	1.05	1.20	1.45	1.45	1.45	1.40	1.45	1.90	2.70
Cdn 10 Yr Bond Yield	quarterly end-of-period - %	**18-Sep-14**	2.20	2.70	3.00	3.05	2.80	2.75	2.70	2.75	2.80	3.10	3.45
Cdn 30 Yr Bond Yield	quarterly end-of-period - %	**18-Sep-14**	2.75	3.40	3.50	3.55	3.35	3.25	3.20	3.25	3.35	3.40	3.65
US 90 day T-bill	quarterly end-of-period - %	**18-Sep-14**	0.10	0.40	0.60	0.85	1.10	1.35	1.25	1.20	1.40	2.05	3.05
US 10 Yr Bond Yield	quarterly end-of-period - %	**18-Sep-14**	2.60	3.10	3.60	3.45	3.25	3.25	3.30	3.35	3.45	3.65	4.00
US 30 Yr Bond Yield	quarterly end-of-period - %	**18-Sep-14**	3.35	3.65	4.15	4.10	3.70	3.65	3.70	3.75	3.80	4.00	4.20
Exchange Rate	(C$/US$)	**18-Sep-14**	1.09	1.12	1.17	1.18	1.16	1.17	1.15	1.15	1.16	1.16	1.18
Cdn CPI	Y/Y - % change	**18-Sep-14**	2.3	2.2	1.8	2.2	2.5	2.6	2.3	2.2	2.1	2.2	2.0
Cdn GDP Price Deflator	Q/Q - % change; annualized rate	**18-Sep-14**	0.8	3.4	2.6	1.9	2.0	2.5	2.4	2.6	2.3	2.7	2.4
US CPI	Y/Y - % change	**18-Sep-14**	2.6	2.4	1.9	2.1	2.2	2.2	2.1	2.1	2.2	2.1	2.0
US GDP Price Deflator	Q/Q - % change; annualized rate	**18-Sep-14**	2.2	2.0	1.8	2.2	2.0	2.2	2.2	2.2	2.2	2.1	2.0

* Financial data up to and including 2016 are quarterly end-of-period forecasts. Economic data up to and including 2016 are quarterly average forecasts. Thereafter, the forecast: are provided in annual granularity, as annual averages.

**If data can only be provided in annual granularity, assume it is the same for each quarter

GDP price deflator is q/q at annual rates, CPI is y/y

Annual averages begin after Q4 2016

Table 4
United States: fixed income market

End of period in %	2013 Q1	Q2	Q3	Q4	2014 Q1	Q2	Q3f	Q4f	2015 Q1f	Q2f	Q3f	Q4f
Key rate												
Federal funds	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.50	1.00	1.25
Treasury bills												
3-month	0.07	0.04	0.02	0.07	0.05	0.04	0.00	0.15	0.30	0.60	1.10	1.35
Federal bonds												
2-year	0.25	0.34	0.32	0.36	0.39	0.42	0.60	1.00	1.40	1.80	2.00	2.25
5-year	0.74	1.36	1.36	1.71	1.71	1.60	1.80	2.10	2.35	2.60	2.80	3.00
10-year	1.85	2.48	2.62	3.01	2.73	2.52	2.55	2.95	3.25	3.45	3.55	3.65
30-year	3.11	3.50	3.69	3.94	3.56	3.34	3.25	3.60	3.80	3.95	4.05	4.10
Yield curve												
5-year - 3-month	0.67	1.32	1.34	1.64	1.66	1.56	1.80	1.95	2.05	2.00	1.70	1.65
10-year - 2-year	1.60	2.14	2.30	2.65	2.34	2.09	1.95	1.95	1.85	1.65	1.55	1.40
30-year - 3-month	3.04	3.46	3.67	3.87	3.51	3.30	3.25	3.45	3.50	3.35	2.95	2.75

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

Table 5
Canada: fixed income market

End of period in %	2013 Q1	Q2	Q3	Q4	2014 Q1	Q2	Q3f	Q4f	2015 Q1f	Q2f	Q3f	Q4f
Key rate												
Federal funds	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50
Treasury bills												
3-month	0.97	1.02	0.98	0.91	0.89	0.94	0.90	1.00	1.00	1.00	1.20	1.50
Federal bonds												
2-year	1.00	1.22	1.19	1.14	1.07	1.10	1.15	1.40	1.60	1.75	1.90	2.10
5-year	1.30	1.80	1.86	1.96	1.71	1.53	1.65	1.95	2.20	2.45	2.65	2.80
10-year	1.76	2.44	2.54	2.78	2.46	2.24	2.20	2.55	2.85	3.05	3.15	3.25
30-year	2.51	2.90	3.07	3.24	2.96	2.78	2.70	3.00	3.25	3.40	3.50	3.55
Yield curve												
5-year - 3-month	0.33	0.78	0.88	1.05	0.82	0.59	0.75	0.95	1.20	1.45	1.45	1.30
10-year - 2-year	0.76	1.22	1.35	1.64	1.39	1.14	1.05	1.15	1.25	1.30	1.25	1.15
30-year - 3-month	1.54	1.88	2.09	2.33	2.07	1.84	1.80	2.00	2.25	2.40	2.30	2.05
Spreads (Canada - U.S.)												
3-month	0.90	0.98	0.96	0.84	0.84	0.90	0.90	0.85	0.70	0.40	0.10	0.15
2-year	0.75	0.88	0.87	0.78	0.68	0.68	0.55	0.40	0.20	-0.05	-0.10	-0.15
5-year	0.56	0.44	0.50	0.25	-0.00	-0.07	-0.15	-0.15	-0.15	-0.15	-0.15	-0.20
10-year	-0.09	-0.04	-0.08	-0.23	-0.27	-0.28	-0.35	-0.40	-0.40	-0.40	-0.40	-0.40
30-year	-0.60	-0.60	-0.62	-0.70	-0.60	-0.56	-0.55	-0.60	-0.55	-0.55	-0.55	-0.55

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

Laurentian Bank Securities - Economic Reseasrch

Forecast Tables

September 5, 2014

Canada

	q/q saar (unless otherwise indicated)								Annual Average				Q4/Q4		
	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2013	2014	2015	2016	2013	2014	2015
Real GDP	**0.9**	**3.4**	**2.7**	**2.4**	**2.4**	**2.4**	**2.5**	**2.6**	**2.0**	**2.4**	**2.5**	**2.7**	**2.7**	**2.4**	**2.5**
Consumption	1.7	4.1	1.8	2.1	2.1	2.1	2.1	2.1	2.4	2.6	2.2	2.2	2.6	2.4	2.1
Business investment	-3.0	1.0	3.1	3.1	3.7	4.2	4.2	4.2	1.1	-0.2	3.5	3.7	-0.2	0.2	4.1
Non-residential structures	-0.7	0.6	2.5	2.5	3.0	3.5	4.0	4.0	2.2	0.3	3.0	3.3	0.5	1.2	3.6
Machinery and equipment	-6.6	1.5	4.0	4.0	4.5	5.0	4.5	4.5	-0.2	-0.9	4.3	4.2	-1.2	0.7	4.6
Residential construction	-5.6	11.9	-3.0	-2.0	-0.5	0.0	0.0	0.0	-0.3	0.3	-0.2	0.0	0.0	0.1	-0.1
Government spending	-0.8	-0.7	1.5	1.3	0.8	0.8	0.8	0.8	0.3	0.0	1.0	1.1	-0.5	0.5	0.8
Exports	-0.7	17.8	4.9	4.0	4.0	4.3	4.9	4.9	2.2	5.0	5.1	5.3	3.7	6.4	4.5
Imports	-5.5	11.1	2.4	2.2	2.4	2.9	2.1	2.1	1.1	1.3	2.9	3.1	1.5	2.3	2.4
Inflation															
Total CPI (y/y %)	1.4	2.2	2.1	2.3	1.9	1.5	1.7	2.0	0.9	2.0	1.8	2.0	0.9	2.3	2.0
Core CPI (y/y %)	1.3	1.7	1.7	1.9	1.8	1.6	1.8	1.9	1.2	1.6	1.8	2.0	1.2	1.9	1.9
Unemployment rate (%) *	7.0	7.0	7.0	7.1	7.0	6.9	6.8	6.7	7.1	7.0	6.8	6.5	-	-	-
Employment	0.4	0.3	0.5	1.0	1.2	1.2	1.2	1.2	1.3	0.6	1.0	1.3	0.9	0.5	1.2
Housing starts (in 000s) *	175	197	190	180	180	180	175	175	188	185	178	178	-	-	-
Corporate profits (y/y %)	13.0	23.3	15.1	15.7	7.2	5.3	4.1	3.4	-1.9	18.5	5.0	3.4	9.4	15.7	3.4
Nominal GDP	6.8	3.9	3.0	4.3	4.3	4.3	4.4	4.6	3.4	4.4	4.1	4.6	3.8	4.5	4.4

*Average rate for the period.

Updated: September 2014

Interest and Foreign Exchange Forecasts

	Historical Data															
	2009	2010	2011	2012	2013Q1	13Q2	13Q3	13Q4	2014Q1	14Q2	14Q3	14Q4	2015Q1	15Q2	15Q3	15Q4
Canada																
Overnight Rate	**0.43**	**0.59**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.50**
3-Month Treasury Bills	0.33	0.56	0.91	0.94	0.96	1.00	0.97	0.91	0.95	0.94	1.00	1.00	1.00	1.00	1.00	1.50
2-Year Bond	1.23	1.54	1.36	1.12	1.00	1.22	1.19	1.13	1.01	1.10	1.10	1.15	1.25	1.40	1.70	2.00
5-Year Bond	2.34	2.48	2.05	1.39	1.30	1.80	1.86	1.95	1.71	1.53	1.60	2.00	2.10	2.20	2.45	2.50
10-Year Bond	3.23	3.24	2.78	1.88	1.88	2.44	2.54	2.77	2.46	2.24	2.10	2.25	2.40	2.65	2.90	3.25
30-Year Bond	3.85	3.77	3.29	2.45	2.50	2.90	3.07	3.24	2.97	2.78	2.65	2.80	3.00	3.20	3.50	3.75
United States																
Federal Funds Rate	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.500**	**1.250**
3-Month Treasury Bills	0.15	0.14	0.05	0.09	0.07	0.04	0.01	0.07	0.05	0.04	0.10	0.10	0.15	0.25	0.50	1.25
2-Year Bond	0.96	0.70	0.45	0.28	0.25	0.36	0.32	0.39	0.44	0.47	0.55	0.70	1.00	1.25	1.55	2.00
5-Year Bond	2.19	1.93	1.52	0.76	0.77	1.41	1.42	1.75	1.73	1.62	1.75	1.80	1.90	2.15	2.50	2.80
10-Year Bond	3.26	3.22	2.78	1.80	1.87	2.52	2.61	3.04	2.73	2.53	2.45	2.60	2.80	3.10	3.35	3.70
30-Year Bond	4.08	4.25	3.91	2.92	3.10	3.68	3.69	3.96	3.56	3.34	3.20	3.30	3.40	3.60	3.80	4.10
Canadian Dollar (US$/C$)	**0.88**	**0.97**	**1.02**	**1.00**	**0.98**	**0.95**	**0.97**	**0.94**	**0.905**	**0.937**	**0.90**	**0.88**	**0.88**	**0.89**	**0.90**	**0.92**

Quarter-end data and annual averages

*** Updated: September 2014**

MONTHLY ECONOMIC MONITOR

Canada
Economic Forecast

(Annual % change)*	2011	2012	2013	2014	2015	Q4/Q4 2013	Q4/Q4 2014	Q4/Q4 2015
Gross domestic product (2007 $)	2.5	1.7	2.0	2.3	2.5	2.7	2.3	2.5
Consumption	2.3	1.9	2.4	2.6	2.3	2.6	2.4	2.2
Residential construction	1.6	6.1	(0.3)	0.9	1.2	(0.0)	1.6	0.4
Business investment	11.1	6.2	1.3	0.0	4.1	(0.2)	1.6	4.3
Government expenditures	(0.6)	1.0	0.3	(0.2)	0.2	(0.5)	0.3	0.0
Exports	4.7	1.5	2.2	5.3	6.7	3.7	7.3	5.9
Imports	5.7	3.1	1.1	1.5	3.5	1.5	3.0	3.1
Change in inventories (millions $)	7,440	6,831	11,927	8,107	2,362	16,770	5,256	2,531
Domestic demand	2.4	2.3	1.4	1.3	1.7	1.2	1.5	1.6
Real disposable income	2.4	2.5	2.4	1.8	2.3	2.0	1.7	2.4
Employment	1.5	1.2	1.3	0.7	1.2	0.9	0.7	1.3
Unemployment rate	7.4	7.3	7.1	7.0	6.7	7.0	6.9	6.5
Inflation	2.9	1.5	0.9	2.0	2.0	0.9	2.5	2.4
Before-tax profits	11.3	(4.9)	(1.7)	10.9	7.7	4.3	13.3	6.5
Federal balance (Public Acc., bil. $)	(26.3)	(18.9)	(17.0)	(4.5)	5.0	....	....	....
Current account (bil. $)	(48.5)	(62.2)	(60.3)	(44.6)	(29.5)	....	....	....

** or as noted*

Financial Forecast**

	Current 9/19/14	Q4 2014	Q1 2015	Q2 2015	Q3 2015	2014	2015
Overnight rate	1.00	1.00	1.00	1.25	1.75	1.00	2.00
Prime rate	3.00	3.00	3.00	3.25	3.75	3.00	4.00
3 month T-Bills	0.92	0.96	1.03	1.47	1.90	0.96	1.96
Treasury yield curve							
2-Year	1.17	1.22	1.33	2.17	2.34	1.22	2.45
5-Year	1.71	1.86	2.02	2.47	2.64	1.86	2.87
10-Year	2.25	2.37	2.52	2.95	3.07	2.37	3.30
30-Year	2.76	2.86	2.98	3.35	3.44	2.86	3.64
CAD per USD	1.09	1.09	1.10	1.12	1.13	1.09	1.13
Oil price (WTI), U.S.$	92	94	96	97	98	94	98

National Bank Financial

*** end of period*

Financial market forecast detail

Interest rates—North America

%, end of period

	Actual						Forecast						Actual		Forecast	
	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	2012	2013	2014	2015
Canada																
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50	1.75	1.00	1.00	1.00	1.75
Three-month	0.98	1.02	0.98	0.91	0.90	0.94	1.10	1.10	1.10	1.35	1.60	1.85	1.05	0.91	1.10	1.85
Two-year	1.00	1.22	1.19	1.13	1.07	1.10	1.15	1.40	1.75	2.00	2.30	2.50	1.05	1.13	1.40	2.50
Five-year	1.30	1.80	1.86	1.95	1.71	1.53	1.70	2.15	2.35	2.50	2.75	3.00	1.30	1.95	2.15	3.00
10-year	1.88	2.44	2.55	2.77	2.46	2.24	2.25	2.60	2.80	3.00	3.25	3.55	1.75	2.77	2.60	3.55
30-year	2.50	2.90	3.07	3.24	2.96	2.78	2.80	3.10	3.25	3.40	3.60	3.85	2.40	3.24	3.10	3.85
Yield curve (10s-2s)	88	122	136	164	139	114	110	120	105	100	95	105	70	164	120	105
United States																
Fed funds	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	0.25	0.25	0.25	1.00
Three-month	0.07	0.04	0.02	0.07	0.05	0.04	0.05	0.05	0.25	0.65	0.90	1.30	0.09	0.07	0.05	1.30
Two-year	0.25	0.36	0.33	0.38	0.45	0.47	0.60	0.95	1.45	1.75	2.20	2.50	0.25	0.38	0.95	2.50
Five-year	0.77	1.41	1.39	1.75	1.74	1.62	1.85	2.30	2.65	2.90	3.20	3.45	0.70	1.75	2.30	3.45
10-year	1.87	2.52	2.64	3.04	2.73	2.53	2.60	3.00	3.25	3.50	3.75	4.00	1.70	3.04	3.00	4.00
30-year	3.10	3.52	3.69	3.96	3.55	3.34	3.35	3.80	3.95	4.15	4.35	4.55	2.90	3.96	3.80	4.55
Yield curve (10s-2s)	162	216	231	266	228	206	200	205	180	175	155	150	145	266	205	150
Yield spreads																
Three-month T-bills	0.91	0.98	0.96	0.84	0.85	0.90	1.05	1.05	0.85	0.70	0.70	0.55	0.96	0.84	1.05	0.55
Two-year	0.75	0.86	0.86	0.75	0.62	0.63	0.55	0.45	0.30	0.25	0.10	0.00	0.80	0.75	0.45	0.00
Five-year	0.53	0.39	0.47	0.20	-0.03	-0.09	-0.15	-0.15	-0.30	-0.40	-0.45	-0.45	0.60	0.20	-0.15	-0.45
10-year	0.01	-0.08	-0.09	-0.27	-0.27	-0.29	-0.35	-0.40	-0.45	-0.50	-0.50	-0.45	0.05	-0.27	-0.40	-0.45
30-year	-0.60	-0.62	-0.62	-0.72	-0.59	-0.56	-0.55	-0.70	-0.70	-0.75	-0.75	-0.70	-0.50	-0.72	-0.70	-0.70

Interest rates—International

%, end of period

	Actual						Forecast						Actual		Forecast	
	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	2012	2013	2014	2015
United Kingdom																
Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.75	0.75	1.00	1.00	0.50	0.50	0.50	1.00
Two-year	0.21	0.41	0.30	0.57	0.71	0.87	0.90	1.20	1.60	1.90	2.20	2.40	0.20	0.57	1.20	2.40
10-year	1.78	2.46	2.50	3.04	2.73	2.68	2.65	3.10	3.40	3.60	3.80	4.10	1.70	3.04	3.10	4.10
Euro Area																
Refinancing rate	0.75	0.50	0.50	0.25	0.25	0.15	0.05	0.05	0.05	0.05	0.05	0.05	0.75	0.25	0.05	0.05
Two-year	-0.02	0.20	0.15	0.24	0.17	0.03	0.00	0.00	0.10	0.10	0.10	0.10	0.00	0.24	0.00	0.10
10-year	1.29	1.73	1.70	2.11	1.57	1.25	1.10	1.30	1.50	1.75	2.00	2.25	1.50	2.11	1.30	2.25
Australia																
Cash target rate	3.00	2.75	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.75	3.00	2.50	2.50	2.75
Two-year swap	2.83	2.58	2.45	2.68	2.78	2.80	2.70	2.85	3.00	3.25	3.50	3.75	2.75	2.68	2.85	3.75
10-year swap	3.42	3.76	3.81	4.23	4.08	4.00	3.60	3.90	4.05	4.30	4.55	4.80	3.00	4.23	3.90	4.80
New Zealand																
Cash target rate	2.50	2.50	2.50	2.50	2.75	3.25	3.50	3.50	3.75	4.00	4.00	4.00	2.50	2.50	3.50	4.00
Two-year	2.85	2.85	3.42	3.81	4.01	3.90	4.20	4.30	4.50	4.60	4.60	4.70	2.60	3.81	4.30	4.70
10-year	3.96	4.16	4.86	5.23	4.62	5.00	5.20	5.40	5.70	5.90	6.00	6.20	3.80	5.23	5.40	6.20

Quarterly Forecasts

Canada	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3f	2014 Q4f	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f
Real GDP (q/q, ann. % change)	3.0	2.7	0.9	3.1	3.0	2.4	2.4	2.4	2.5	2.5
Real GDP (y/y, % change)	2.2	2.7	2.1	2.5	2.4	2.3	2.7	2.5	2.4	2.4
Consumer Prices (y/y, % change)	1.1	0.9	1.4	2.2	2.1	2.2	2.0	1.9	2.1	2.2
Core CPI (y/y % change)	1.3	1.2	1.3	1.7	1.9	2.0	2.0	2.0	2.0	2.0
United States										
Real GDP (q/q, ann. % change)	4.5	3.5	-2.1	4.6	2.8	3.0	3.1	3.2	3.3	3.3
Real GDP (y/y, % change)	2.3	3.1	1.9	2.6	2.2	2.0	3.4	3.1	3.2	3.3
Consumer Prices (y/y, % change)	1.5	1.2	1.4	2.1	1.9	2.1	2.1	2.0	2.3	2.3
Core CPI (y/y % change)	1.7	1.7	1.6	1.9	1.8	1.9	2.0	2.0	2.2	2.2

Financial Markets

Central Bank Rates

(%, end of period)

Americas	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3f	2014 Q4f	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f
Bank of Canada	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25
U.S. Federal Reserve	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00
Bank of Mexico	3.75	3.50	3.50	3.00	3.00	3.00	3.00	3.25	3.75	4.00
Central Bank of Brazil	9.00	10.00	10.75	11.00	11.00	11.00	11.25	11.25	11.50	11.50
Bank of the Republic of Colombia	3.25	3.25	3.25	4.00	4.50	4.75	4.75	5.00	5.00	5.00
Central Reserve Bank of Peru	4.25	4.00	4.00	4.00	3.50	3.50	3.50	3.50	3.50	3.50
Central Bank of Chile	5.00	4.50	4.00	4.00	3.25	3.00	3.00	3.25	3.25	3.25
Europe										
European Central Bank	0.50	0.25	0.25	0.15	0.05	0.05	0.05	0.05	0.05	0.05
Bank of England	0.50	0.50	0.50	0.50	0.50	0.50	0.75	1.00	1.25	1.50
Swiss National Bank	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Asia/Oceania										
Reserve Bank of Australia	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.75	3.00	3.25
People's Bank of China	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Reserve Bank of India	7.50	7.75	8.00	8.00	8.00	8.00	7.75	7.50	7.50	7.50
Bank of Korea	2.50	2.50	2.50	2.50	2.25	2.25	2.25	2.50	2.75	3.00
Bank Indonesia	7.25	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
Bank of Thailand	2.50	2.25	2.00	2.00	2.00	2.00	2.00	2.00	2.25	2.50

Canada	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3f	2014 Q4f	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f
3-month T-bill	0.98	0.92	0.89	0.95	0.92	1.00	1.00	1.05	1.20	1.55
2-year Canada	1.19	1.14	1.07	1.11	1.12	1.25	1.50	1.80	2.00	2.20
5-year Canada	1.86	1.94	1.71	1.53	1.63	1.80	2.10	2.45	2.75	2.85
10-year Canada	2.54	2.76	2.46	2.24	2.15	2.50	2.70	3.10	3.25	3.40
30-year Canada	3.07	3.23	2.96	2.78	2.67	2.85	3.00	3.45	3.55	3.65
United States										
3-month T-bill	0.01	0.07	0.03	0.02	0.02	0.15	0.25	0.70	0.90	1.20
2-year Treasury	0.32	0.38	0.42	0.46	0.57	0.95	1.50	1.90	2.20	2.40
5-year Treasury	1.39	1.74	1.72	1.63	1.76	2.05	2.35	2.80	3.10	3.20
10-year Treasury	2.61	3.03	2.72	2.53	2.49	2.90	3.15	3.60	3.75	3.90
30-year Treasury	3.69	3.97	3.56	3.36	3.20	3.35	3.50	4.05	4.15	4.20
Canada-U.S. Spreads										
3-month T-bill	0.98	0.85	0.86	0.93	0.90	0.85	0.75	0.35	0.30	0.35
2-year	0.87	0.76	0.65	0.65	0.56	0.30	0.00	-0.10	-0.20	-0.20
5-year	0.47	0.20	-0.01	-0.10	-0.13	-0.25	-0.25	-0.35	-0.35	-0.35
10-year	-0.07	-0.27	-0.26	-0.29	-0.34	-0.40	-0.45	-0.50	-0.50	-0.50
30-year	-0.62	-0.74	-0.59	-0.58	-0.53	-0.50	-0.50	-0.60	-0.60	-0.55

INTEREST RATE OUTLOOK

	2014				2015				2016			
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA												
Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.50	1.50	1.50	1.75	2.00	2.00
3-mth T-Bill Rate	0.90	0.94	0.95	0.95	0.95	1.05	1.40	1.40	1.55	1.85	1.95	2.05
2-yr Govt. Bond Yield	1.07	1.10	1.15	1.30	1.50	1.70	1.95	2.05	2.20	2.45	2.65	2.85
5-yr Govt. Bond Yield	1.71	1.53	1.70	1.90	2.10	2.35	2.60	2.75	2.95	3.10	3.15	3.25
10-yr Govt. Bond Yield	2.46	2.24	2.25	2.40	2.65	2.85	3.05	3.25	3.40	3.55	3.65	3.75
30-yr Govt. Bond Yield	2.96	2.78	2.75	2.85	3.05	3.25	3.45	3.60	3.75	3.85	3.90	4.00
10-yr-2-yr Govt Spread	1.39	1.14	1.10	1.10	1.15	1.15	1.10	1.20	1.20	1.10	1.00	0.90
U.S.												
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	1.25	1.50	1.75
3-mth T-Bill Rate	0.05	0.04	0.05	0.10	0.20	0.25	0.30	0.55	0.80	1.00	1.25	1.50
2-yr Govt. Bond Yield	0.44	0.47	0.55	0.80	1.05	1.35	1.40	1.60	1.85	2.05	2.20	2.35
5-yr Govt. Bond Yield	1.73	1.62	1.85	2.05	2.25	2.50	2.55	2.70	2.85	3.00	3.05	3.15
10-yr Govt. Bond Yield	2.73	2.53	2.60	2.70	2.90	3.10	3.15	3.25	3.35	3.45	3.55	3.65
30-yr Govt. Bond Yield	3.56	3.34	3.30	3.35	3.45	3.60	3.60	3.60	3.70	3.80	3.90	4.00
10-yr-2-yr Govt Spread	2.29	2.06	2.05	1.90	1.85	1.75	1.75	1.65	1.50	1.40	1.35	1.30
CANADA - U.S SPREADS												
Can - U.S. T-Bill Spread	0.85	0.90	0.90	0.85	0.75	0.80	1.10	0.85	0.75	0.85	0.70	0.55
Can - U.S. 10-Year Bond Spread	-0.27	-0.29	-0.35	-0.30	-0.25	-0.25	-0.10	0.00	0.05	0.10	0.10	0.10

F: Forecast by TD Bank Group as at September 2014. All forecasts are end-of-period. Source: Bloomberg, Bank of Canada, Federal Reserve.

FOREIGN EXCHANGE OUTLOOK

Currency	Exchange rate	2014				2015				2016			
		Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Exchange rate to U.S. dollar													
Japanese yen	JPY per USD	103	101	108	108	109	109	110	111	112	112	107	107
Euro	USD per EUR	1.38	1.37	1.29	1.29	1.28	1.26	1.24	1.22	1.22	1.22	1.24	1.24
U.K. pound	USD per GBP	1.67	1.71	1.65	1.68	1.68	1.68	1.65	1.61	1.58	1.58	1.59	1.57
Exchange rate to Canadian dollar													
U.S. dollar	USD per CAD	0.91	0.94	0.90	0.89	0.87	0.88	0.90	0.90	0.90	0.90	0.88	0.88
Japanese yen	JPY per CAD	93.4	95.0	97.2	96.1	94.8	95.9	99.0	99.9	100.8	100.8	94.2	94.2
Euro	CAD per EUR	1.52	1.46	1.43	1.45	1.47	1.43	1.38	1.36	1.36	1.36	1.41	1.41
U.K. pound	CAD per GBP	1.84	1.83	1.84	1.88	1.94	1.91	1.84	1.78	1.76	1.76	1.81	1.78

F: Forecast by TD Bank Group as at September 2014. All forecasts are end-of-period. Source: Federal Reserve, Bloomberg, TDBG.

COMMODITY PRICE FORECASTS

	Price	52-Week	52-Week	2014F				2015F				Annual Average			
	Sep-24	High	Low	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	2013	2014F	2015F	2016F
Crude Oil (WTI, $US/bbl)	94	108	92	104	95	97	92	91	90	92	90	94	97	91	90
Natural Gas ($US/MMBtu)	3.84	8.03	3.36	3.57	4.18	3.95	4.25	4.50	4.25	3.85	4.00	3.51	3.99	4.15	4.06
Gold ($US/troy oz.)	1307	1418	1189	1338	1247	1284	1235	1200	1225	1275	1300	1579	1276	1250	1275
Silver (US$/troy oz.)	17.7	22.8	17.7	22.2	20.1	19.75	18.60	17.50	19.00	19.75	20.25	28.3	20.2	19.1	20.0
Copper (cents/lb)	307	336	292	325	326	318	308	300	300	280	280	346	319	290	275
Nickel (US$/lb)	7.77	9.53	6.03	6.34	6.33	8.45	8.00	9.00	9.50	9.75	10.00	7.36	7.28	9.56	10.44
Aluminum (Cents/lb)	89	96	76	81	79	89	94	88	84	86	86	88	86	86	88

F: Forecast by TD Bank Group as at September 2014; All forecasts are period averages; Source: Bloomberg, USDA (Haver).

FINANCIAL OUTLOOK

U.S.	2014 Q1	2014 Q2	2014 Q3F	2014 Q4F	2015 Q1F	2015 Q2F	2015 Q3F	2015 Q4F	2016 Q1F	2016 Q2F	2016 Q3F	2016 Q4F	2017 Q1F	2017 Q2F	2017 Q3F	2017 Q4F	2018 Q1F	2018 Q2F	2018 Q3F	2018 Q4F
Target for Fed Funds Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.25	3.25
3-mth T-Bill Rate (%)	0.05	0.04	0.05	0.10	0.20	0.25	0.30	0.55	0.80	1.00	1.25	1.50	1.70	2.00	2.20	2.45	2.70	2.90	2.95	2.95
2-yr Govt. Bond Yield (%)	0.44	0.47	0.55	0.80	1.05	1.35	1.40	1.60	1.85	2.05	2.20	2.35	2.50	2.65	2.75	2.90	3.05	3.20	3.20	3.25
5-yr Govt. Bond Yield (%)	1.73	1.62	1.85	2.05	2.25	2.50	2.55	2.70	2.85	3.00	3.05	3.15	3.25	3.35	3.45	3.50	3.60	3.70	3.75	3.80
10-yr Govt. Bond Yield (%)	2.73	2.53	2.60	2.70	2.90	3.10	3.15	3.25	3.35	3.45	3.55	3.65	3.70	3.80	3.90	4.00	4.10	4.20	4.25	4.30
Canada																				
Overnight Target Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.50	1.50	1.50	1.75	2.00	2.00	2.50	2.50	3.00	3.00	3.00	3.00	3.00	3.00
3-mth T-Bill Rate (%)	0.90	0.94	0.95	0.95	0.95	1.05	1.40	1.40	1.55	1.85	1.95	2.05	2.50	2.75	2.95	2.95	2.95	2.95	2.95	2.95
2-yr Govt. Bond Yield (%)	1.07	1.10	1.15	1.30	1.50	1.70	1.95	2.05	2.20	2.45	2.65	2.85	2.90	3.05	3.25	3.25	3.25	3.25	3.25	3.25
5-yr Govt. Bond Yield (%)	1.71	1.53	1.70	1.90	2.10	2.35	2.60	2.75	2.95	3.10	3.15	3.25	3.35	3.40	3.45	3.50	3.55	3.60	3.60	3.60
10-yr Govt. Bond Yield (%)	2.46	2.24	2.25	2.40	2.65	2.85	3.05	3.25	3.40	3.55	3.65	3.75	3.80	3.90	4.00	4.05	4.05	4.10	4.10	4.15
USD per CAD	0.91	0.94	0.90	0.89	0.87	0.88	0.90	0.90												
CAD per GBP	1.84	1.83	1.84	1.88	1.94	1.91	1.84	1.78												
USD per GBP	1.67	1.71	1.65	1.68	1.68	1.68	1.65	1.61												

U.S.	Average Annual 09	10	11	12	13	14F	15F	16F	17F	4th Qtr/4th Qtr 09	10	11	13	14F	15F	16F	17F
Target for Fed Funds Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.44	1.38	2.38	0.25	0.25	0.25	0.25	0.25	0.75	1.75	2.75
3-mth T-Bill Rate (%)	0.15	0.16	0.04	0.08	0.05	0.06	0.33	1.14	2.09	0.06	0.12	0.02	0.07	0.10	0.55	1.50	2.45
2-yr Govt. Bond Yield (%)	1.00	0.67	0.44	0.29	0.33	0.57	1.35	2.11	2.70	1.14	0.61	0.25	0.38	0.80	1.60	2.35	2.90
5-yr Govt. Bond Yield (%)	2.30	1.91	1.45	0.78	1.33	1.81	2.50	3.01	3.39	2.69	2.01	0.83	1.75	2.05	2.70	3.15	3.50
10-yr Govt. Bond Yield (%)	3.35	3.16	2.62	1.83	2.52	2.64	3.10	3.50	3.85	3.85	3.30	1.89	3.04	2.70	3.25	3.65	4.00
Canada																	
Overnight Target Rate (%)	0.31	0.69	1.00	1.00	1.00	1.00	1.25	1.81	2.75	0.25	1.00	1.00	1.00	1.00	1.50	2.00	3.00
3-mth T-Bill Rate (%)	0.26	0.66	0.87	0.92	0.97	0.94	1.20	1.85	2.79	0.19	0.97	0.82	0.91	0.95	1.40	2.05	2.95
2-yr Govt. Bond Yield (%)	1.25	1.54	1.31	1.11	1.14	1.16	1.80	2.54	3.11	1.47	1.67	0.95	1.13	1.30	2.05	2.85	3.25
5-yr Govt. Bond Yield (%)	2.39	2.41	1.94	1.38	1.73	1.71	2.45	3.11	3.43	2.77	2.41	1.27	1.95	1.90	2.75	3.25	3.50
10-yr Govt. Bond Yield (%)	3.27	3.13	2.64	1.85	2.38	2.34	2.95	3.59	3.94	3.61	3.11	1.94	2.77	2.40	3.25	3.75	4.05
USD per CAD	0.89	0.98	1.00	1.00	0.96	0.91	0.89			0.96	1.01	0.98	0.94	0.89	0.90		
CAD per GBP	1.78	1.57	1.58	1.60	1.64	1.85	1.87			1.69	1.55	1.58	1.76	1.88	1.78		
USD per GBP	1.57	1.54	1.58	1.60	1.58	1.68	1.66			1.62	1.56	1.55	1.66	1.68	1.61		

TD Bank September 25, 2014

Table 24
Interest Rates
(Percent)

IHS Global Insight - Sept 2014

Government of Canada	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1
Treasury Bills																					
3 Months	0.88	0.93	0.95	0.97	1.00	1.00	1.08	1.40	2.17	2.59	3.07	3.54	4.12	4.51	4.50	4.50	4.50	4.50	4.50	4.50	4.50
6 Months	0.91	0.95	1.00	1.02	1.05	1.05	1.14	1.46	2.22	2.64	3.12	3.59	4.17	4.57	4.55	4.55	4.55	4.55	4.55	4.55	4.55
Bonds																					
1-3 Years	1.02	1.06	1.13	1.14	1.19	1.23	1.31	1.61	2.31	2.70	3.14	3.58	4.12	4.49	4.47	4.47	4.47	4.47	4.47	4.47	4.47
3-5 Years	1.38	1.41	1.43	1.46	1.58	1.66	1.75	2.00	2.58	2.91	3.28	3.66	4.13	4.43	4.42	4.42	4.42	4.42	4.42	4.42	4.42
5 Years	1.63	1.58	1.61	1.66	1.82	1.94	2.03	2.25	2.76	3.05	3.37	3.71	4.14	4.40	4.39	4.39	4.39	4.39	4.39	4.39	4.39
5-10 Years	1.97	1.91	2.07	2.16	2.42	2.63	2.71	2.86	3.18	3.37	3.59	3.83	4.15	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31
10 Years	2.42	2.29	2.49	2.62	2.97	3.26	3.34	3.42	3.57	3.68	3.79	3.95	4.17	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
10+ Years	2.81	2.69	2.91	3.02	3.36	3.64	3.71	3.78	3.92	4.02	4.13	4.28	4.50	4.56	4.55	4.55	4.55	4.54	4.54	4.54	4.53
30 Years	2.95	2.84	3.02	3.12	3.46	3.73	3.80	3.87	4.01	4.11	4.22	4.36	4.58	4.64	4.63	4.63	4.62	4.62	4.62	4.61	4.61

Government of Canada	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1	23Q2	23Q3	23Q4	24Q1	24Q2	24Q3	24Q4
Treasury Bills																							
3 Months	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
6 Months	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55	4.55
Bonds																							
1-3 Years	4.70	4.70	4.70	4.70	4.70	4.70	4.70	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47	4.47
3-5 Years	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42	4.42
5 Years	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39
5-10 Years	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31
10 Years	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
10+ Years	4.53	4.53	4.53	4.53	4.53	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52	4.52
30 Years	4.61	4.60	4.60	4.60	4.60	4.60	4.60	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59

Conference Board - Sept 2014

Description:	Implicit Price Deflator - GDP at Market Prices (2007=1.0)	Consumer Price Index (2002 = 100)	Canada - 3 Month Treasury Bill ()	Exchange Rate (Canada/ U.S.)	United States - 3 Month Treasury Bill ()	Canada, Federal Bonds: Long-Term ()	30 Year T-Bill Rate ()	GDP Deflator (2009=100)	Canada, Federal Bonds: 10 Years ()	Consumer Price Index, Manitoba (2002=1.0)
2014.01	1.13	1.24	0.88	1.10	0.05	2.95	3.68	107.69	2.42	1.24
2014.02	1.13	1.26	0.93	1.09	0.03	2.84	3.44	108.22	2.29	1.26
2014.03	1.13	1.26	0.94	1.09	0.03	2.61	3.21	109.04	2.05	1.26
2014.04	1.14	1.26	0.94	1.11	0.03	2.57	3.11	109.61	2.00	1.27
2015.01	1.14	1.27	0.96	1.11	0.08	3.11	3.22	110.16	2.66	1.27
2015.02	1.15	1.27	1.00	1.11	0.08	3.11	3.17	110.72	2.67	1.28
2015.03	1.15	1.28	1.13	1.11	0.15	3.28	3.17	111.26	2.88	1.29
2015.04	1.16	1.29	1.21	1.11	0.28	3.41	3.24	111.83	3.05	1.29
2016.01	1.17	1.29	1.25	1.11	0.35	3.53	3.30	112.41	3.21	1.30
2016.02	1.17	1.30	1.42	1.11	0.50	3.65	3.32	112.98	3.38	1.31
2016.03	1.18	1.31	1.67	1.11	0.75	3.76	3.44	113.56	3.54	1.31
2016.04	1.18	1.31	1.92	1.10	1.07	3.92	3.57	114.13	3.69	1.32
2017.01	1.19	1.32	2.17	1.10	1.52	4.06	3.81	114.68	3.84	1.33
2017.02	1.20	1.33	2.42	1.10	1.99	4.20	4.06	115.23	3.98	1.33
2017.03	1.20	1.33	2.67	1.10	2.30	4.34	4.24	115.78	4.11	1.34
2017.04	1.21	1.34	2.92	1.10	2.55	4.46	4.37	116.35	4.24	1.35
2018.01	1.22	1.35	3.17	1.10	2.80	4.58	4.49	116.92	4.35	1.35
2018.02	1.22	1.35	3.42	1.10	3.15	4.69	4.65	117.51	4.47	1.36
2018.03	1.23	1.36	3.63	1.10	3.40	4.80	4.77	118.11	4.58	1.37
2018.04	1.24	1.37	3.71	1.10	3.68	4.98	4.90	118.72	4.75	1.37
2019.01	1.24	1.38	3.71	1.10	3.91	4.98	5.02	119.31	4.75	
2019.02	1.25	1.38	3.71	1.10	4.02	4.98	5.13	119.88	4.75	
2019.03	1.25	1.39	3.71	1.10	4.02	4.98	5.13	120.45	4.75	
2019.04	1.26	1.40	3.71	1.10	4.02	4.98	5.13	121.00	4.75	
2020.01	1.27	1.40	3.71	1.10	4.02	4.98	5.13	121.55	4.75	
2020.02	1.27	1.41	3.71	1.10	4.02	4.98	5.13	122.09	4.75	
2020.03	1.28	1.42	3.71	1.10	4.02	4.98	5.13	122.63	4.75	
2020.04	1.29	1.43	3.71	1.10	4.02	4.98	5.13	123.18	4.75	
2021.01	1.29	1.43	3.71	1.10	4.02	4.98	5.13	123.73	4.75	
2021.02	1.30	1.44	3.71	1.10	4.02	4.98	5.13	124.27	4.75	
2021.03	1.31	1.45	3.71	1.10	4.02	4.98	5.13	124.81	4.75	
2021.04	1.31	1.45	3.71	1.10	4.02	4.98	5.13	125.35	4.75	
2022.01	1.32	1.46	3.71	1.10	4.02	4.98	5.13	125.89	4.75	
2022.02	1.33	1.47	3.71	1.10	4.02	4.98	5.13	126.44	4.75	
2022.03	1.33	1.48	3.71	1.10	4.02	4.98	5.13	127.01	4.75	
2022.04	1.34	1.48	3.71	1.10	4.02	4.98	5.13	127.58	4.75	
2023.01	1.35	1.49	3.71	1.10	4.02	4.98	5.13	128.03	4.75	
2023.02	1.35	1.50	3.71	1.10	4.02	4.98	5.13	128.56	4.75	
2023.03	1.36	1.51	3.71	1.10	4.02	4.98	5.13	129.12	4.75	
2023.04	1.37	1.52	3.71	1.10	4.02	4.98	5.13	129.70	4.75	
2024.01	1.38	1.52	3.71	1.10	4.02	4.98	5.13	130.28	4.75	
2024.02	1.38	1.53	3.71	1.10	4.02	4.98	5.13	130.87	4.75	
2024.03	1.39	1.54	3.71	1.10	4.02	4.98	5.13	131.46	4.75	
2024.04	1.40	1.55	3.71	1.10	4.02	4.98	5.13	132.04	4.75	
2025.01	1.40	1.55	3.71	1.10	4.02	4.98	5.13	132.64	4.75	
2025.02	1.41	1.56	3.71	1.10	4.02	4.98	5.13	133.23	4.75	
2025.03	1.42	1.57	3.71	1.10	4.02	4.98	5.13	133.83	4.75	
2025.04	1.42	1.58	3.71	1.10	4.02	4.98	5.13	134.43	4.75	
2026.01	1.43	1.59	3.71	1.10	4.02	4.98	5.13	135.03	4.75	
2026.02	1.44	1.59	3.71	1.10	4.02	4.98	5.13	135.62	4.75	
2026.03	1.45	1.60	3.71	1.10	4.02	4.98	5.13	136.23	4.75	
2026.04	1.45	1.61	3.71	1.10	4.02	4.98	5.13	136.84	4.75	
2027.01	1.46	1.62	3.71	1.10	4.02	4.98	5.13	137.45	4.75	
2027.02	1.47	1.63	3.71	1.10	4.02	4.98	5.13	138.06	4.75	
2027.03	1.48	1.64	3.71	1.10	4.02	4.98	5.13	138.68	4.75	
2027.04	1.48	1.64	3.71	1.10	4.02	4.98	5.13	139.30	4.75	
2028.01	1.49	1.65	3.71	1.10	4.02	4.98	5.13	139.93	4.75	
2028.02	1.50	1.66	3.71	1.10	4.02	4.98	5.13	140.56	4.75	
2028.03	1.51	1.67	3.71	1.10	4.02	4.98	5.13	141.17	4.75	
2028.04	1.52	1.68	3.71	1.10	4.02	4.98	5.13	141.78	4.75	
2029.01	1.52	1.69	3.71	1.10	4.02	4.98	5.13	142.41	4.75	
2029.02	1.53	1.69	3.71	1.10	4.02	4.98	5.13	143.05	4.75	
2029.03	1.54	1.70	3.71	1.10	4.02	4.98	5.13	143.71	4.75	
2029.04	1.55	1.71	3.71	1.10	4.02	4.98	5.13	144.35	4.75	

December 2014

Integrated Financial Forecast (IFF14)

2014/15 - 2033/34

Financial Planning
Finance & Regulatory

Manitoba Hydro

INTEGRATED FINANCIAL FORECAST (IFF14)

2014/15 – 2033/34

FINANCIAL PLANNING DEPARTMENT
FINANCE & REGULATORY

December, 2014

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INTEGRATED FINANCIAL FORECAST (IFF14)

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF14 Forecast			
	2013/14	2014/15	2015/16	2016/17	2023/24
PROJECTED RATE INCREASES					
- ELECTRIC	3.50%[1]	2.75%[2]	3.95%[3]	3.95%[3]	3.95%
- GAS (non-commodity)	1.07%	-	-	-	1.75%
NET INCOME					
- ELECTRIC	$146	$ 102	$ 115	$ 59	($124)
- GAS	20	7	4	0	4
- SUBSIDIARIES	8	6	6	7	11
CAPITAL EXPENDITURES					
- ELECTRIC	$ 1 348	$ 2 023	$ 2 491	$ 3 073	$ 681
- GAS	35	48	65	51	43
DEBT/EQUITY RATIO	76:24	77:23	81:19	83:17	89:11
INTEREST COVERAGE RATIO	1.28	1.17	1.17	1.07	0.92
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.35	0.99	1.05	0.96	1.24
RETAINED EARNINGS	$2 716	$ 2 831	$ 2 901	$ 2 968	$2 226

[1] The 3.5% rate increase was implemented effective May 1, 2013. In accordance with PUB Order 43/13, 1.5% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.
[2] The interim 2.75% rate increase was implemented effective May 1, 2014. In accordance with PUB Order 49/14, 0.75% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.
[3] The proposed 3.95% rate increases would be effective April 1, 2015 and April 1, 2016.

EXECUTIVE SUMMARY

The Consolidated Integrated Financial Forecast (IFF14) projects Manitoba Hydro's financial results and financial position for the 20-year period from 2014/15 to 2033/34. Segmented forecasts are also provided for the electricity (MH14), natural gas (CGM14), and corporate subsidiaries (CS14).

The key changes to the financial outlook in IFF14 are as follows:

- Lower general consumers revenue ($3.3 billion) due mainly to increased demand side management savings, a lower approved rate increase for 2014/15 and lower projected indicative rate increases from 2031/32 to 2033/34.

- Lower projected net extraprovincial revenues ($2.0 billion) due mainly to the suspension of Conawapa, as well as lower projected export prices, partially offset by increased energy available for export as a result of increased demand side management (DSM) energy and capacity savings;

- Lower projected capital expenditure forecast ($7.5 billion) mainly due to the suspension of Conawapa ($10.1 billion) and the deferral of Pointe du Bois Powerhouse Rebuild ($1.5 billion). This decrease is partially offset by higher projected capital costs for sustaining capital ($1.9 billion), Bipole III ($1.3 billion), DSM ($0.9 billion), and Keeyask ($0.3 billion).

- Lower finance expense ($2.6 billion) and depreciation expense (down $0.2 billion) that result from lower projected interest rates, reductions in depreciation rates as recommended in the updated depreciation study, and the suspension of Conawapa. These decreases are partially offset by the higher projected capital costs for sustaining capital, Bipole III, DSM, and Keeyask.

In the near term to 2017/18, net income is higher compared to IFF13, largely due to favourable water flow conditions and lower finance and depreciation expenses. However, there are lower net earnings projected in the remaining years of IFF14 due to the key changes noted above. The projected net losses between 2018/19 to 2025/26 largely reflect the significant increase in carrying costs associated with Bipole III, sustaining capital expenditures and Keeyask which will essentially double the net plant of the Corporation. After that period, the higher export revenues associated with Keeyask and cumulative domestic rate increases return the Corporation to profitability.

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by the Fall of 2016).

Manitoba Hydro continues to project minimum indicative rate increases of 3.95% per year in IFF14 to 2030/31 and then 2.00% thereafter to 2033/34. In order to maintain the 3.95% rate increases in the near to medium term, Manitoba Hydro continues to pursue further cost containment initiatives and the deferral or cancellation of a number of capital projects. Should a severe drought occur during the first 10-year period, net income and the equity ratio would be further challenged and higher rate increases would be necessary.

Consistent with IFF13, the equity ratio is projected to deteriorate from the current 24% level to 11% equity by 2022/23 before gradually beginning to recover to reach the 25% equity target by 2033/34. There is no change in attaining the 25% equity target compared to IFF13.

The other key financial targets – interest coverage and capital coverage – are also below target for several years but recover to the target range within the later years of the 20 year forecast.

The major factors contributing to the need for the 3.95% rate increases are the expenditures that are necessary to meet the growing electricity requirements of the Province and the requirement to replace distribution, transmission and substation assets that were installed up to 60 years ago. The aging infrastructure issue is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the rate increases being projected in IFF14, it is expected that Manitoba's domestic electricity customers will continue to have rates that are affordable and competitive with other utilities in North America.

The following is a summary of projected net income and key financial ratios over the 20-year period to 2033/34:

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2015	-	$115	$2,831	77:23	1.17	0.99
2016	3.95%	126	2,901	81:19	1.17	1.05
2017	3.95%	67	2,968	83:17	1.07	0.96
2018	3.95%	75	3,043	84:16	1.07	1.13
2019	3.95%	(75)	2,968	85:15	0.94	0.94
2020	3.95%	(102)	2,866	86:14	0.92	0.86
2021	3.95%	(164)	2,702	87:13	0.88	0.87
2022	3.95%	(192)	2,510	88:12	0.86	0.98
2023	3.95%	(174)	2,336	89:11	0.87	1.11
2024	3.95%	(109)	2,226	89:11	0.92	1.24
2025	3.95%	(38)	2,188	89:11	0.97	1.27
2026	3.95%	(9)	2,179	89:11	0.99	1.31
2027	3.95%	97	2,276	88:12	1.07	1.47
2028	3.95%	168	2,444	87:13	1.12	1.57
2029	3.95%	279	2,724	86:14	1.20	1.68
2030	3.95%	415	3,139	84:16	1.30	1.91
2031	3.95%	551	3,690	82:18	1.41	1.99
2032	2.00%	662	4,352	79:21	1.52	2.14
2033	2.00%	741	5,093	76:24	1.60	2.22
2034	2.00%	842	5,935	73:27	1.70	2.34




Section 1

1.0 INTRODUCTION

The Consolidated Integrated Financial Forecast (IFF14) provides projections of Manitoba Hydro's financial results and financial position for the 20-year period from 2014/15 to 2033/34. Its purpose is to project the Corporation's long-term financial direction. The detailed forecasts in the first two years of the IFF are used for monthly reporting and variance analysis. The IFF serves as the primary forecast to determine the need for rate increases that are necessary for the Corporation to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets.

The forecast is the culmination of an extensive integrated planning cycle at Manitoba Hydro. It is based on the best available information at the time it is prepared and includes forward looking information that incorporates expectations, estimates and assumptions concerning the future which are subject to change. Key inputs to the Integrated Financial Forecast include:

- Economic Outlook
- Energy Price Outlook
- Electricity Export Price Forecast
- Power Smart Plan
- Electric Load Forecast
- Natural Gas Volume Forecast
- Domestic Revenue Forecast
- Power Resource Plan
- Generation Costs and Interchange Revenue Forecast
- Capital Expenditure Forecast
- Operating, Maintenance & Administrative Expense Forecast

This forecast supersedes the 2013 Integrated Financial Forecast (IFF13) which was finalized in February of 2014.

2.0 RATES and ECONOMIC VARIABLES

2.1 Electricity Rates

In accordance with Manitoba Public Utilities Board (PUB) Order 49/14, IFF14 includes an interim 2.00% rate increase effective May 1, 2014 for revenues directed to General Consumers Revenue with a further 0.75% for revenues directed to the Bipole III Deferral Account. The Bipole III Deferral Account was established in PUB Order 43/13 to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service. IFF14 assumes that the revenues accumulated in the Bipole III Deferral Account will be drawn down over a 3-year period following the Bipole III in-service (July 2018) and that cumulative rate increases applied to the Bipole III Deferral Account will revert to general consumers revenue thereafter.

IFF14 proposes additional rate increases of 3.95% effective April 1 in each of 2015 and 2016. The April 1, 2015 rate increase will be requested on an interim basis to be finalized by the PUB in the 2015 General Rate Application. Indicative additional average annual electric rate increases of 3.95% are projected each April from 2017/18 through 2030/31 and then 2.00% from 2031/32 to 2033/34.

The rate increases proposed for 2015/16 and 2016/17 have been approved by the Manitoba Hydro-Electric Board (MHEB) for submission to the PUB. Proposed rate increases subsequent to 2017/18 may be changed in future forecasts and are presented for illustrative purposes only. Each year's revision to the Integrated Financial Forecast is based on the current year's assumptions including energy supply and demand, projected interest, escalation and exchange rates, projected prices for exported energy, operating and capital forecasts and other factors. Changes in any of these assumptions will have an impact on the projected future results. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

2.2 Gas Rates

Manitoba Hydro does not propose any non-gas rate changes for 2014/15 through 2016/17. Thereafter, IFF14 assumes non-gas rate increases as required to generate Centra Gas net income of approximately $3 million each year. Gas general rate applications are also subject to review and approval by the MHEB prior to filing with the PUB.

2.3 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of October 2014 to reflect current economic conditions at that time. Projected rates for key economic indicators are listed below with the 2013 projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	US-CDN Exchange Rate (C$/US$)
2014/15	1.8% (2.0%)	0.95% (1.15%)	3.50% (4.05%)	1.10 (1.03)
2015/16	1.9% (2.0%)	1.30% (2.10%)	4.10% (4.35%)	1.12 (1.01)
2016/17	2.0% (2.0%)	2.40% (3.10%)	4.50% (4.60%)	1.12 (1.01)
2017/18	2.0% (2.0%)	3.10% (3.70%)	4.80% (5.40%)	1.12 (1.03)
2023/24	2.1% (2.0%)	3.90% (3.90%)	5.20% (5.75%)	1.10 (1.03)

* Excludes the 1% Provincial guarantee fee.

The forecasts of US-CDN exchange rates and interest rates have been decreased since the fall 2013 forecasts. The major factors influencing the drop in the forecast of US-CDN exchange rates is due to lower oil price projections and differing expectations with respect to Canadian and US monetary policy and growth. With the actual interest rates for the first three quarters of 2014 resulting in materially lower outcomes than what was forecasted and with the Bank of Canada's commitment to maintain short-term interest rates at near low levels, the updated lower starting point and gradual progression has resulted in lower interest rate forecasts. Forecasters now generally expect the Bank of Canada to hold off on raising interest rates to at least mid 2015 with the overall consensus being that the long-term rate will be lower than the pre-recession period.

3.0 MANITOBA ELECTRICITY LOAD FORECAST

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2014 Electric Load Forecast. The Load Forecast includes demand side management savings achieved to date as well as projected savings achieved through codes and standards. Planned additional savings are incorporated in the forecast of general consumers revenue separately from the Load Forecast and are discussed in Section 4.0 below.

The 2014 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.8% for gross firm energy and 1.6% for gross total peak over the 10-year forecast period to 2023/24 (compared to 1.4% for both in IFF13). Gross firm energy supplied to the Manitoba load is projected to grow from 25 639 GW.h in 2014/15 to 29 626 GW.h by 2023/24. Over the same 10-year period, total system peak is projected to grow from 4 716 MW in 2014/15 to 5 400 MW in 2023/24. The 20-year average growth is expected to slow to 1.5% for gross firm energy and 1.3% for gross total peak by 2033/34. The system load factor is projected to remain relatively constant between approximately 62% and 63%.

Compared to the 2013 forecast, gross firm energy is projected to be up 614 GW.h (nearly 1½ year's load growth) by 2023/24 primarily due to increases in the pipeline sector as well as increases in the mass market sector due to a higher residential customer forecast in the short term. Over the longer term, the increase in gross firm energy is expected to be reduced to 129 GW.h (less than half a year's load growth) by 2032/33 due to a lower residential customer forecast in the longer term and an increase in the projected impacts of codes and standards. The gross total peak forecast is 104 MW higher in 2023/24 and 28 MW lower than the 2013 forecast in 2032/33, for similar reasons as the change in energy.

Over the 20-year forecast period, the impact of the change in the load forecast compared to IFF13 (before energy and capacity savings from incremental DSM) is minimal.

4.0 DEMAND SIDE MANAGEMENT

IFF14 incorporates the demand side management domestic customer energy and demand savings and investments forecast in the 2014-2017 Power Smart Plan and 15 year supplemental forecast. The Power Smart Plan, endorsed by the Province of Manitoba, sets out to realize electricity savings of 1 136 MW and 3 978 GW.h, natural gas savings of 108 million cubic meters and combined global greenhouse gas emission reductions of 2.9 million tonnes by 2028/29. This activity represents 12.7% of the estimated electric load forecast offsetting 66% of projected load growth during this period and 5.3% of the estimated natural gas volume forecast by 2028/29, further reducing natural gas consumption in Manitoba.

Combined with energy savings achieved to date, total electrical savings of 1 635 MW and 6 286 GW.h and total natural gas savings of 211 million cubic meters will be realized by 2028/29. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 4.6 million tonnes by 2028/29. This activity represents 20.1% of the estimated electric load forecast and 10.2% of the estimated natural gas volume forecast by 2028/29.

The projected cost of demand side management included in IFF14 is $1.2 billion over the 20-year period to 2033/34 or $0.9 billion greater than IFF13.

Overall, the forecast of General Consumers Revenue in IFF14 is $3.3 billion lower compared to IFF13 due mainly to the projected energy and capacity savings resulting from DSM as well as the lower rate increase approved for 2014/15 and lower projected indicative rate increases from 2031/32 to 2033/34.

5.0 EXTRA-PROVINCIAL REVENUE

IFF14 includes the following long-term firm export sales:

Northern States Power 150 MW Seasonal Diversity	To April 2015
Northern States Power 200 MW Seasonal Diversity	To April 2016
Northern States Power 500 MW Power Sale	To April 2014
Minnesota Power 50 MW System Participation Sale	May 2009 to April 2015
Minnesota Power 50 MW System Participation Sale	May 2015 to May 2020
Minnesota Power 250 MW System Participation Sale	June 2020 to May 2035
Great River Energy 150 MW Seasonal Diversity Sale	May 1995 to April 2015
Great River Energy 200 MW Seasonal Diversity Sale	May 2015 to March 2030
Northern States Power 125 MW System Power Sale	May 2021 to April 2025
Northern States Power 375/325 MW System Power Sale	May 2015 to April 2025
Northern States Power 350 MW Seasonal Diversity Sale	May 2015 to April 2025
Wisconsin Public Service 100 MW Sale	June 2021 to May 2027
Wisconsin Public Service 108 MW System Participation	June 2014 to May 2021
SaskPower 25 MW System Participation Sale	November 2015 to May 2022
American Electric Power 50 MW ZRC	May 2016 to May 2018
NextEra 10 MW Sale	June 2014 May 2015
NextEra 40 MW Sale	June 2015 to May 2016
NextEra 100 MW Sale	June 2016 to May 2018

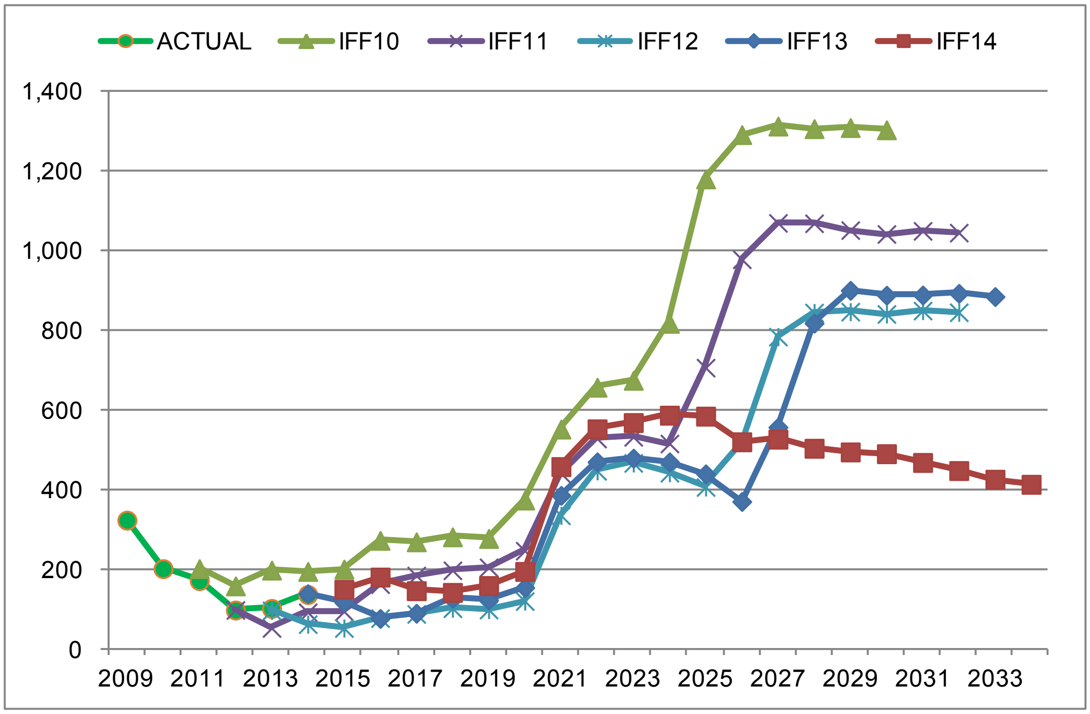
Extra-provincial sales volumes are forecast for the first forecast year (2014/15) based upon the expected inflow conditions as of October 2014 and actual reservoir and lake level elevations as of September 2014. The second forecast year (2015/16) uses the median of 80 years of historic inflows and initial reservoir and lake level elevations carried forward from the 2014/15 forecast. For 2016/17 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14).

Over the 20-year forecast period, net extra-provincial revenue (extra-provincial revenue net of water rentals and fuel and power purchased) decreases $2.0 billion compared to IFF13. The decrease is mainly due to the suspension of Conawapa in IFF14 as well as slightly lower forecasted export prices. This decrease is partially offset by higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast through increased DSM programs and higher forecasted US-CDN exchange rates.

The following Figure 5-1 shows the comparative net extra-provincial revenues from IFF10 through IFF14.

Figure 5-1: Extra-provincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



In comparison to the 2013 Electric Export Price Forecast, the 2014 forecast projects prices for a long term dependable electricity product will be, on average, 7% lower over the period 2016/17 to 2035/36. Over that time horizon energy prices (both on and off peak) are forecast to be an average of 3% lower with the value of capacity down 15% relative to the 2013 outlook. The decrease reflects the forecast for lower natural gas prices, with a minor offset due to the stabilizing effects of relatively flat year over year coal and carbon price forecasts, along with some additional clarity on US environmental regulation and resulting coal fleet retirements.

6.0 ELECTRICITY SUPPLY

Manitoba Hydro's 2014/15 Power Resource Plan indicates new generation is required by 2038/39 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2037/38.

The following resources contribute to the ability to meet future Manitoba energy and capacity requirements.

	MW	Dependable GW.h	In-Service Date
HVDC Bipole III Line & 2300 MW of Converter Capability	80	177	2018/19
Keeyask	695	3 000	2019/20
Demand Side Management Program			
Planned Additional	582	2 797	By 2028/29

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by the Fall of 2016).

7.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February of 2013, the Canadian Accounting Standards Board (AcSB) extended the optional IFRS transition date for rate-regulated entities an additional year to January 1, 2015 in consideration of the commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting. Manitoba Hydro has adopted the optional transition date deferral and will be transitioning to IFRS effective April 1, 2015 for its 2015/16 fiscal period with comparative information presented for 2014/15.

On January 30, 2014, the IASB issued a new interim standard IFRS 14 Regulatory Deferral Accounts which is effective January 1, 2016 with early adoption permitted. The interim standard allows rate-regulated entities to continue to recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) upon transition to IFRS. The intent of the standard is to provide temporary guidance until the IASB completes its comprehensive project on Rate-regulated Activities which is expected to take several years.

Manitoba Hydro will early adopt IFRS 14 upon its April 1, 2015 transition and as such, will continue to recognize its regulated assets and liabilities upon transition to IFRS. While it is uncertain as to the final position the IASB will take as part of its comprehensive Rate-regulated Activities project, it has been assumed in IFF14 that regulatory deferral accounts will continue to be recognized throughout the forecast period to 2033/34.

Generally speaking, the transition to IFRS will result in timing differences between when expenditures are recognized into income between Canadian Generally Accepted Accounting Principles (CGAAP) and IFRS. Manitoba Hydro recognizes that the different financial reporting requirements under IFRS will both increase and decrease annual net income. As such, Manitoba Hydro has considered the range of potential impacts and where possible, has selected accounting policies aimed at minimizing the overall impact to net income and customer rates.

The primary impacts of IFRS that are included in IFF14 are as follows:

- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred;
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates; and
- Unamortized experience gains and losses on pension balances will be reclassified to accumulated other comprehensive income (AOCI) upon transition to IFRS.

The following table Figure 7-1 outlines the projected IFRS impacts to retained earnings, AOCI and net income:

Figure 7-1: IFRS Impacts on Retained Earnings and Net Income

IFRS Impacts
Increase/(Decrease)

($Millions)

	Retained Earnings	AOCI	Net Income 2015/16
Capital Taxes	-	-	3
Administrative Overhead	(56)	-	(57) *
Pension & Employee Benefits	(24)	(445)	3
Meter Compliance, Exchange and Sampling	-	-	5
Removal of Negative Salvage	62	-	64
Change to Equal Life Group Depreciation	(36)	-	(38)
Total	**(54)**	**(445)**	**(20)**

*Impacts to net income are net of depreciation & amortization.

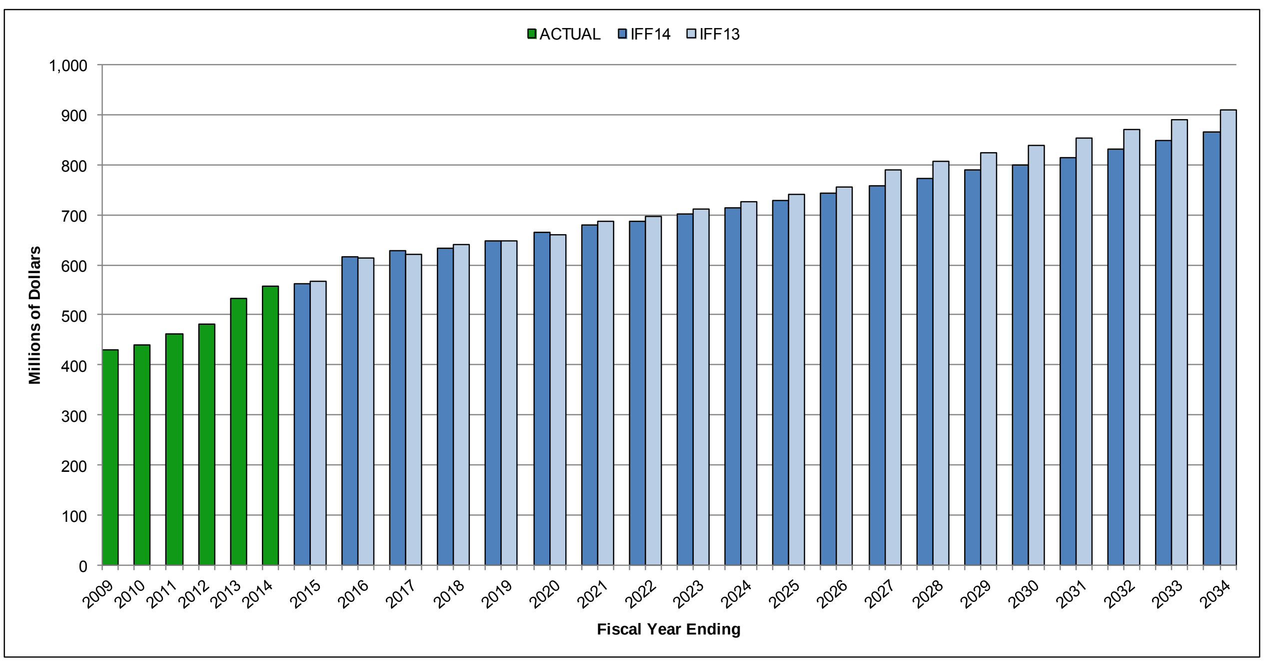
8.0 OPERATING & ADMINISTRATIVE EXPENSE

Operating, Maintenance & Administrative (OM&A) Expenses in IFF14 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and electric and gas distribution systems.

Figure 8-1 below shows the OM&A expense projected in IFF14 compared to IFF13. On an overall basis, OM&A remains relatively unchanged from IFF13. IFRS adjustments remain in place beginning 2015/16 and more aggressive cost containment measures continue to be implemented to keep costs below inflationary levels. Reductions in the later years are due to a reclassification of Great Northern Transmission Line costs to Fuel and Power Purchases for IFF14, as well, as the deferral of Bipole III for one year and suspension of Conawapa.

For the period from 2014/15 to 2021/22, it is assumed that OM&A cost increases, excluding accounting changes, will be limited to below inflationary levels of 1%. This is an advancement of one year compared to IFF13 which assumed the 1% escalation commenced in 2015/16. For the remainder of the forecast, OM&A rises at the same level as inflation except in years where major new generation and transmission comes into service in 2018/19 (Bipole III), 2019/20 (Keeyask) and 2020/21 (500kV tie line). Increases associated with load growth over the forecast period are assumed to be achieved through continuing productivity improvements.

Figure 8-1: Operating, Maintenance and Administrative Expense

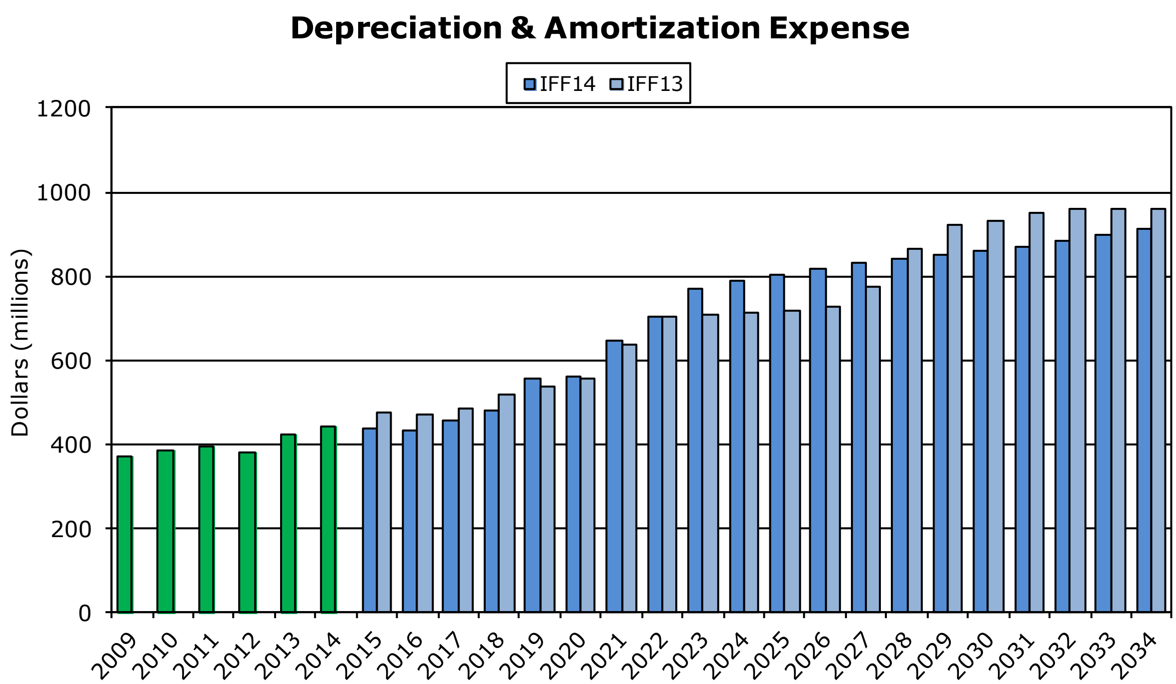


9.0 DEPRECIATION & AMORTIZATION EXPENSE

The Depreciation and Amortization Expense included in IFF14 is based on a comprehensive depreciation study that was completed in October 2014.

Figure 9-1 below provides a comparison of the Depreciation and Amortization Expense between IFF14 and IFF13. Depreciation and Amortization Expense is $0.2 billion lower in IFF14 over the 20-year forecast period compared to IFF13 primarily due to the reduction in depreciation rates resulting from updated asset service lives as recommended in the depreciation study (decrease of $0.9 billiion), as well as the suspension of Conawapa (decrease of $0.9 billion). This reduction is largely offset by the higher capital costs of Bipole III, DSM and Major and Base Capital Expenditures (increase of $1.5 billion).

Figure 9-1: Depreciation and Amortization Expense



10.0 WUSKWATIM POWER LIMITED PARTNERSHIP

IFF14 assumes that the Nisichawayasihk Cree Nation (NCN) will acquire up to a 33% common unit ownership interest in the Wuskwatim Power Limited Partnership (WPLP). The WPLP will operate and maintain the Wuskwatim generating station and Manitoba Hydro will purchase all of the generation under the terms of the Wuskwatim Project Development Agreement (PDA) signed by Manitoba Hydro and NCN in 2006. Manitoba Hydro's income statement reflects all of the partnership revenues and costs with non-controlling interest representing NCN's share of the projected net income or losses in WPLP (shown as a deduction or addition before net income, respectively). The partnership's net assets are offset by an amount for NCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

During 2014, Manitoba Hydro and NCN reached an agreement in principle with respect to Wuskwatim PDA Supplement #2. IFF14 assumes the terms of the agreement in principle commencing in 2014/15. The projected net impact to Manitoba Hydro averages approximately $15 million per year over the 20-year forecast period.

It is expected that the agreement in principle will be finalized into a legally binding agreement over the next several months.

11.0 KEEYASK HYDROPOWER LIMITED PARTNERSHIP

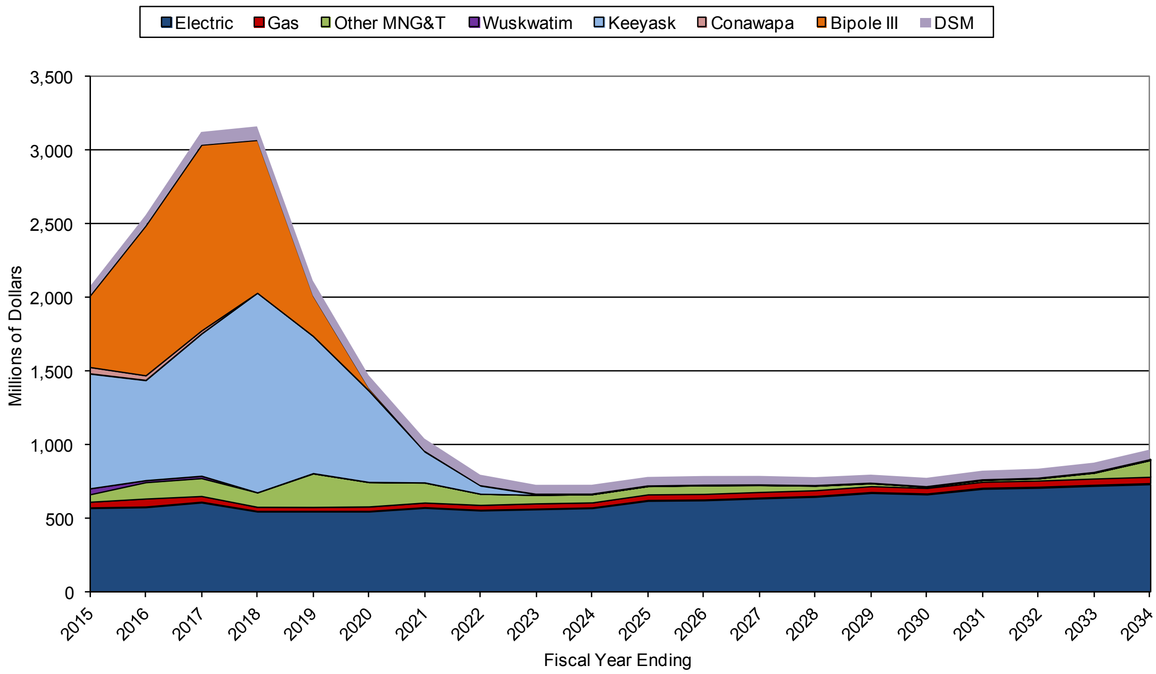
The Keeyask Cree Nations (KCN's), including Tataskweyak Cree Nation and War Lake First Nation (operating together as Cree Nation Partners), Fox Lake Cree Nation and York Factory First Nation, have the right to acquire up to 25% in the Keeyask Hydropower Limited Partnership (KHLP). The partnership will construct, operate and maintain the Keeyask generating station and Manitoba Hydro will purchase all of the generation under the terms of the Joint Keeyask Development Agreement (JKDA) signed by Manitoba Hydro and the KCN's in 2009. Manitoba Hydro's income statement reflects all of the partnership revenues and costs. The partnership's net assets are offset by an amount for the KCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

IFF14 assumes the KCN's will hold a 17.5% common ownership interest up to the in-service of the final Keeyask generating unit and then elect to invest in the preferred ownership option. The preferred distributions to the KCN's have been reclassified as an expense (fuel & power purchases) in IFF14 from non-controlling interest in previous forecasts.

12.0 CAPITAL EXPENDITURE FORECAST

Capital expenditures are forecast to be $17.8 billion to 2023/24 and $26.0 billion to 2033/34. Figure 12-1 below illustrates projected capital expenditures by major category.

Figure 12-1: Capital Expenditure Forecast CEF14



The CEF14 includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19. In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20. Manitoba Hydro continues to develop the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation. The Province also endorsed Manitoba Hydro’s new, more aggressive demand side management PowerSmart plan which targets a 250% increase in consumption savings.

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall 2016).

Over the 10-year forecast to 2023/24, capital expenditures are $3.4 billion lower compared to the previous capital expenditure forecast (CEF13). The decrease is mainly due to the suspension of Conawapa. In addition, reductions have been identified for the Gillam Redevelopment and Expansion program, deferral of the Slave Falls Overhaul project, and the cancellation of the Dorsey 230 kV Zone Building and Firm Import Upgrades projects. These decreases in the 10-year forecast period are partially offset by increases in sustaining capital expenditures and DSM expenditures as well as Bipole III and Keeyask projects.

Over the longer term to 2033/34, capital expenditures are $7.5 billion lower compared to CEF13 due to the suspension of Conawapa and deferral of the Pointe du Bois Powerhouse Rebuild project. The decrease is partially offset by increased expenditures for sustaining infrastructure, Bipole III, DSM and Keeyask as previously indicated for the 10-year period.

The following Table 12-1 provides a summary of CEF14 and the revisions from CEF13.

Table 12-1: Summary of Projected Capital Expenditures

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	2,062	2,483	2,543	2,358	2,061	1,878	1,372	1,755	2,319	2,359	21,191
Incr (Decr)	9	73	580	803	52	(408)	(333)	(962)	(1,595)	(1,635)	(3,416)
CEF14	2,071	2,556	3,124	3,161	2,113	1,470	1,039	793	724	724	17,774

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
CEF13	2,162	2,048	1,838	1,399	1,098	922	828	680	630	679	33,474
Incr (Decr)	(1,384)	(1,264)	(1,054)	(623)	(305)	(151)	(8)	154	245	285	(7,521)
CEF14	778	784	785	776	793	771	820	834	875	963	25,953

The following Table 12-2 provides a summary of the total changes to the 10 and 20-year forecast.

Table 12-2: Summary of CEF14 Project Increases/(Decreases)

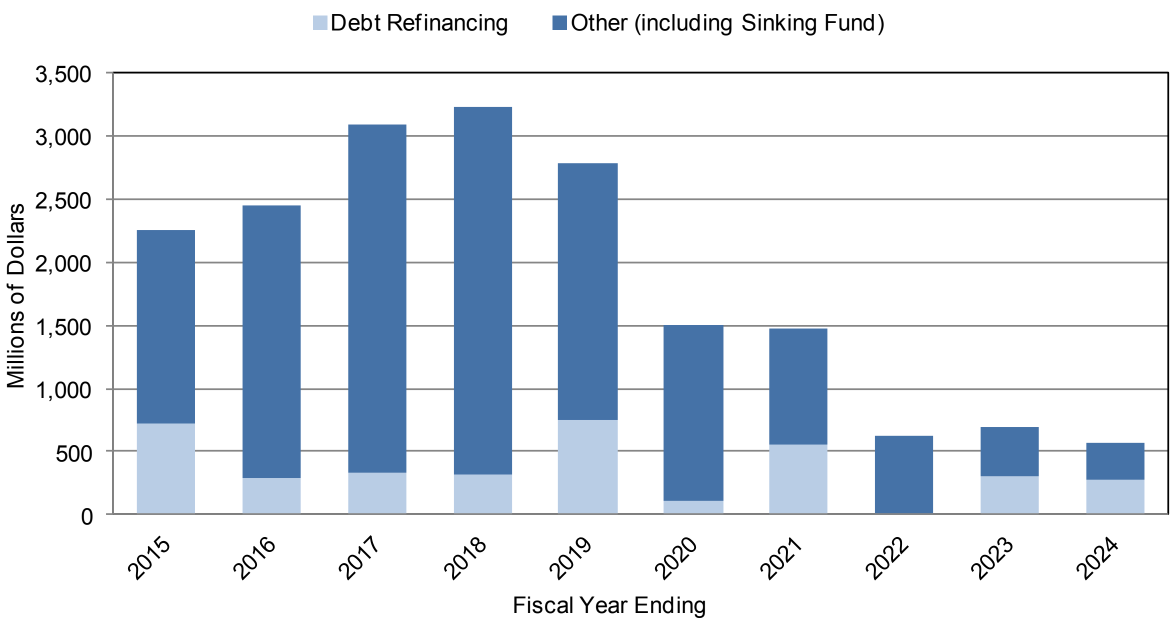
	Total Projected Cost	10 Year Increase (Decrease)	20 Year Increase (Decrease)
	($ Millions)		
Conawapa - Generation	397	(6,052)	(10,065)
Base Capital Target	NA	422	1,957
Pointe du Bois Powerhouse Rebuild	1,852	(19)	(1,471)
Bipole III - Converter Stations	2,675	881	881
Demand Side Management *	NA	463	802
Additional North South Trasmission	-	(90)	(475)
Bipole III - Transmission Line	1,655	407	407
Keeyask - Generation	6,496	349	349
Gillam Redevelopment and Expansion Program	266	(77)	(100)
Gas Demand Side Management *	NA	50	92
Bipole III - Collector Lines	260	71	71
Dorsey 230KV Zone Building	-	(63)	(63)
New Adelaide Station - 66/12kV	62	62	62
Slave Falls Major Overhauls	126	(63)	-
Other System Upgrades		243	32
		(3,416)	(7,521)

* Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under the interim standard that continues to permit rate regulated accounting.

13.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 13-1 below.

Figure 13-1: Projected Consolidated Borrowing Requirements



Manitoba Hydro arranges long-term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the Manitoba Hydro-Electric Board). Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; to a maximum of 35% of the total debt portfolio. Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

14.0 NATURAL GAS DEMAND & SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 94% of customers representing approximately 62% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The volume forecast incorporates Manitoba Hydro's Fixed Price Offering for primary gas, which was introduced in 2008/09 and offers customers one, three, and five-year fixed price contracts.

The forecast incorporates the transportation and supplementary gas requirements, not only for Manitoba Hydro's customers but also for those consumers who purchase their primary gas from brokers and marketers.

The total natural gas sales volume forecast decreases 40 million cubic meters (1.9%) from 2013/14 to 2014/15 and continues to decrease by 6.5 million cubic meters (0.3% per year) to 2023/24. The decrease is primarily attributed to a change in the expected average use across all customer sectors, by reducing their non-process related natural gas usage due to conversions to high efficiency furnaces, improvements in insulation levels and conversion of Residential sector from natural gas to electric water heaters.

15.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

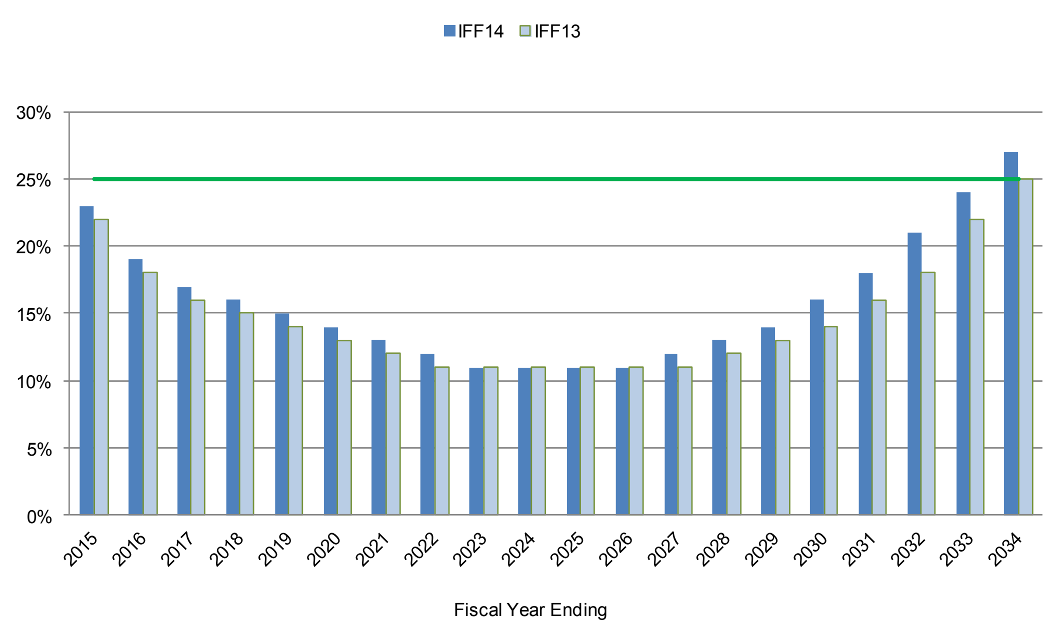
Debt/Equity Ratio	Achieve and maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting major new generation and transmission)

Financial targets may not be achieved during years of major investment in the generation and transmission system.

15.1 Debt/Equity Ratio

The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Figure 15-1 below shows the projected consolidated equity ratio for IFF14 compared to IFF13. High levels of capital investment over the next ten years combined with reduced revenues result in deterioration of the equity ratio to 11% by 2022/23. The equity ratio shows improvement following the in-service of Keeyask and is projected to return to the target 25% by the end of the 20-year forecast period in 2033/34 (same year as in IFF13).

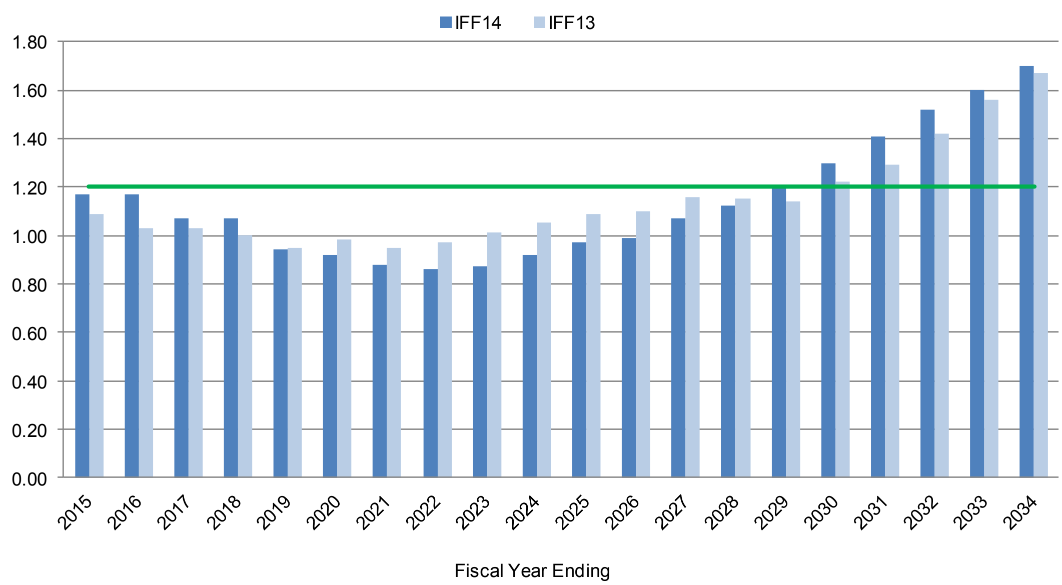
Figure 15-1: Projected Consolidated Equity Ratio



15.2 Interest Coverage Ratio

The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 15-2 below shows that the reduction in net income compared to the previous forecast IFF13 and increase in capital requirements for Bipole III, Keeyask, DSM and to replace aging infrastructure results in interest coverage ratios lower than target for a period of fourteen years. In the longer term, interest coverage is projected to return to the 1.20 target level by 2028/29.

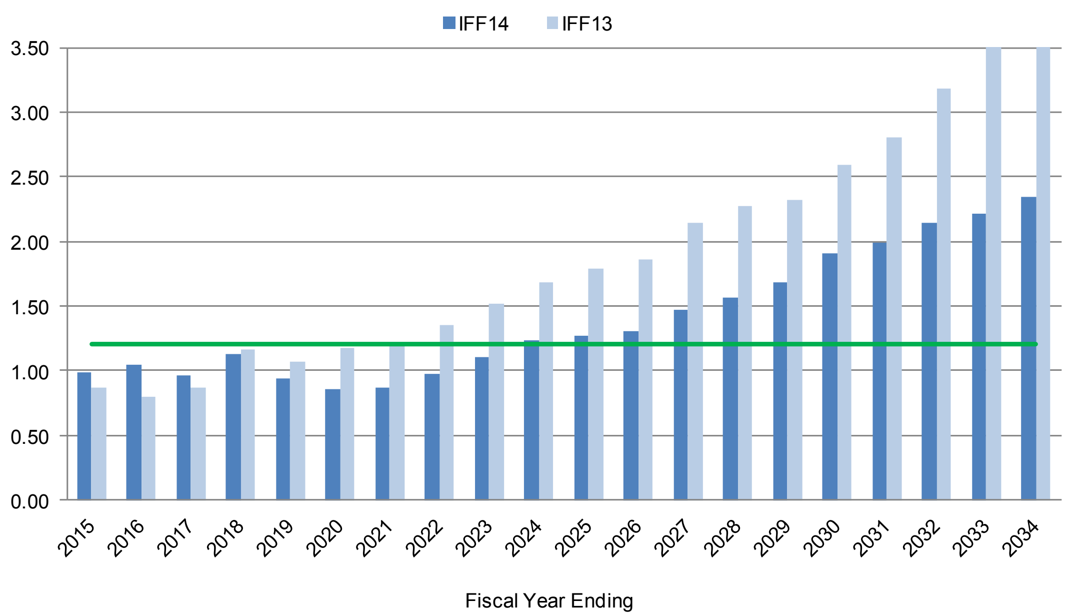
Figure 15-2: Projected Consolidated Interest Coverage Ratio



15.3 Capital Coverage Ratio

The capital coverage ratio measures the ability of current period internally generated funds to finance sustaining capital expenditures (excluding major new generation and related transmission). Figure 15-3 below shows the comparative capital coverage ratios between IFF14 and IFF13. Capital coverage is below target for the first nine years of the forecast due to the reduction in net income and increasing capital requirements to replace aging infrastructure. Thereafter, projected cash flows are sufficient to enable this target to be met in the remaining years of the forecast after the in-service of the Keeyask Generating Station.

Figure 15-3: Projected Consolidated Capital Coverage Ratio



16.0 SENSITIVITY ANALYSIS

The 20-Year Financial Outlook includes a number of key assumptions as described in the previous sections. A change to one or more of those assumptions could have a significant impact on projected financial results. This section provides an indication of the financial impact of changes in the following assumptions:

- Domestic load growth
- Interest rates
- Foreign exchange rates
- Export prices
- Capital expenditures
- Water flow conditions
- Rate Increases

Table 16-1 below shows the change in retained earnings and incremental even annual rate increases/(decreases) required to achieve the same level of retained earnings in 2023/24 as forecast in IFF14.

Table 16-1: Financial Impacts of Sensitivity Analysis

	2016/17	2020/21	2023/24	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease)
Low Domestic Load Growth	(4)	(24)	(32)	0.04%
High Domestic Load Growth	(4)	54	65	-0.08%
+ 1% Interest	(47)	(423)	(1,071)	1.27%
- 1% Interest	45	398	987	-1.31%
C$/US$ Down 0.10 (C$ Strengthening)	5	(3)	(159)	0.20%
C$/US$ Up 0.10 (C$ Weakening)	(5)	3	159	-0.20%
Low Export Price	(44)	(304)	(704)	0.88%
High Export Price	28	245	626	-0.81%
5 Year Drought (starting in 2016/17)	N/A	(1,711)	N/A	2.43%
+ 1% Rate Increase in 2016	31	116	206	-0.26%
- 1% Rate Increase in 2016	(31)	(115)	(200)	0.26%
Capital Down $50 million/year	7	85	206	-0.26%
Capital Up $50 million/year	(7)	(85)	(205)	0.26%

16.1 Domestic Load Growth Sensitivity

The 2014 Electric Load Forecast is prepared with the expectation that there is a 50% chance that actual Manitoba energy requirements could be higher or lower than forecast. To evaluate the potential variation in the load forecast due to long term economic effects, 10% and 90% confidence bands (±1.28 standard deviations) were selected to represent proxies for the low and high load forecast scenarios. The variability in gross firm energy could be ±1 093 GW.h by 2023/24 or ±261 MW in system peak energy.

Historically, domestic load requirements higher than forecast would result in greater adverse financial impacts than lower domestic loads due to the higher value of opportunity export sales compared to domestic revenues. With the weakening of forecast electricity export prices compared to previous forecasts, wholesale market export and domestic retail average rates have inverted and the resulting revenue impacts are positive to Manitoba Hydro over the 10-year forecast. In the high domestic load growth scenario, net income impacts in the near term (to 2019/20) that are greater in absolute terms than the net income impacts under the low domestic load growth scenario. This is due to the availability of Brandon until its decommissioning date in 2019/20 to supply firm Manitoba load (which is not available to supply firm export sales). Brandon would be dispatched before displacing uncommitted firm sales which are limited over this period.

Under low load growth, the reduction to revenues is greater than the increase in export sales resulting in a net reduction to revenues and net income.

16.2 Interest Rates Sensitivity

Interest rates assumed in IFF14 are projected to rise gradually over the first six years of the forecast. The interest rate sensitivity indicates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds.

16.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to be weaken to $1.12 (C$/US$) over the first five years of the forecast and then is projected to slightly strengthen to $1.10 (C$/US$). In the short to medium term of the forecast, net income is relatively neutral to changes in the exchange rate, due to the effective hedge provided by Manitoba Hydro's foreign exchange policy. The exchange rate sensitivity indicates the financial impacts of the C$/US$ exchange rate being 0.10 higher (C$ weakening) or lower (C$ strengthening) than forecast.

16.4 Export Prices Sensitivity

IFF14 reflects the expected electricity export prices derived from several independent price forecasts for the Midwest independent System Operator (MISO) region. Each price forecast consultant has their own electricity price forecast models, assumptions and view of the future. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These factors include:

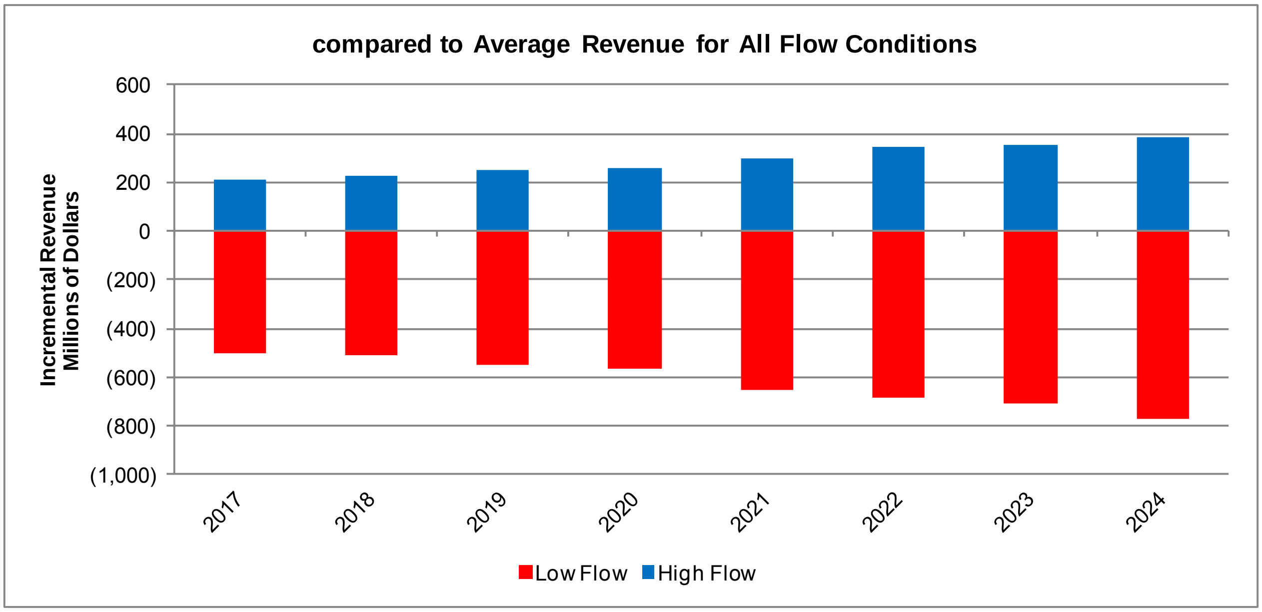
- Thermal fuel forecasts (coal and natural gas);
- Future load growth forecasts;
- Profile of existing generation (fuel type, efficiency and operating parameters);
- Profile of potential new generation (fuel type, efficiency, capital cost and required rates of return);
- Generation requirements;
- Power market rules; and
- Future regulation/legislation related to SO2 (sulfur dioxide), NOX (nitrous oxide), Hg (mercury) and CO2 (carbon dioxide) emissions, as well as cooling water releases and coal ash handling.

There is uncertainty in each of these factors, and particular uncertainty as to how future legislative requirements may evolve. In addition to the expected case, forecast consultants provide high and low price cases with their views of potential long-term lower and higher variations from expected export prices. The export price sensitivities provided in this analysis reflect these low and high export price cases, coupled with low and high natural gas prices.

16.5 Drought/Water Flow Sensitivity

IFF14 reflects the average revenues and expenses of 102 different potential system inflow conditions that occurred historically from 1912/13 to 2013/14. Although the forecast inherently includes the revenues and expenses associated with both the highest and lowest inflow conditions, the actual inflow could vary significantly from forecast in any given year as shown in Figure 16-2. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years.

Figure 16-2: Variability of Net Interchange Revenue



A prolonged period of low flows has a significant financial impact. The current estimate of a recurrence of the historic five-year drought from 1987/88 to 1991/92 is approximately $1.7 billion by the end of the drought period in 2020/21. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2016/17 compared to the average net revenues resulting from all historic flow cases. The costs of drought could rise under a scenario of higher electricity export and thermal fuel prices.

16.6 Rate Increase Sensitivity

Table 16-1 indicates the financial impact of a +/-1% change in the proposed electric rate increase in 2015/16 and demonstrates that required even annual rate increases of 3.95% will increase or decrease by +/- 0.26% over the remaining eight years to 2023/24.

16.7 Capital Expenditure Sensitivity

The capital expenditure sensitivity reflects the financial effects of inflationary or deflationary changes to Major & Base Capital relative to general inflation levels and/or reduction or increases to expenditures necessary to meet reliability, regulatory or customer requirements.

Section 2

17.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF14)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers	1,856	1,935	1,971	2,066	2,145	2,229	2,309	2,395	2,490	2,595
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
	2,235	2,337	2,387	2,487	2,613	2,744	3,125	3,339	3,448	3,582
Cost of Gas Sold	269	277	247	246	246	246	247	248	247	246
	1,965	2,060	2,140	2,241	2,367	2,497	2,878	3,091	3,201	3,336
Other	60	60	62	64	65	66	68	69	71	72
	2,025	2,121	2,203	2,305	2,432	2,563	2,946	3,160	3,272	3,408
EXPENSES										
Operating and Administrative	562	617	628	635	649	664	680	687	701	715
Finance Expense	530	546	585	621	792	928	1,235	1,367	1,376	1,393
Depreciation and Amortization	437	434	455	480	556	560	648	702	771	788
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	119	127	141	155	164	165	166	172	172	183
Other Expenses	29	30	31	32	32	33	34	34	35	36
	1,936	2,007	2,144	2,236	2,512	2,669	3,120	3,353	3,445	3,514
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	115	126	67	75	(75)	(102)	(164)	(192)	(174)	(109)
Additional General Consumers Revenue										
General electricity rate increases	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Financial Ratios										
Equity	23%	19%	17%	16%	15%	14%	13%	12%	11%	11%
Interest Coverage	1.17	1.17	1.07	1.07	0.94	0.92	0.88	0.86	0.87	0.92
Capital Coverage	0.99	1.05	0.96	1.13	0.94	0.86	0.87	0.98	1.11	1.24

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers	2,703	2,819	2,937	3,062	3,193	3,336	3,485	3,584	3,686	3,792
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
	3,699	3,747	3,881	3,984	4,113	4,263	4,396	4,485	4,569	4,675
Cost of Gas Sold	246	245	245	244	244	244	244	244	245	245
	3,453	3,502	3,636	3,740	3,869	4,019	4,152	4,241	4,324	4,431
Other	74	75	77	78	80	82	83	85	87	89
	3,527	3,577	3,713	3,818	3,949	4,101	4,235	4,326	4,411	4,520
EXPENSES										
Operating and Administrative	729	744	758	773	789	801	815	832	848	865
Finance Expense	1,396	1,394	1,385	1,385	1,370	1,349	1,312	1,247	1,212	1,168
Depreciation and Amortization	803	817	829	843	850	861	871	883	897	914
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	184	185	187	188	189	189	191	193	196	198
Other Expenses	37	37	38	39	40	41	41	42	43	44
	3,560	3,585	3,613	3,644	3,663	3,676	3,672	3,649	3,653	3,659
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(38)	(9)	97	168	279	415	551	662	741	842
Additional General Consumers Revenue										
General electricity rate increases	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
General gas rate increases	0.50%	1.25%	0.50%	1.00%	0.75%	0.75%	0.50%	1.00%	0.75%	1.00%
Financial Ratios										
Equity	11%	11%	12%	13%	14%	16%	18%	21%	24%	27%
Interest Coverage	0.97	0.99	1.07	1.12	1.20	1.30	1.41	1.52	1.60	1.70
Capital Coverage	1.27	1.31	1.47	1.57	1.68	1.91	1.99	2.14	2.22	2.34

CONSOLIDATED PROJECTED BALANCE SHEET (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,860	18,665	19,921	20,809	25,805	29,211	34,113	34,790	35,458	36,157
Accumulated Depreciation	(5,864)	(6,214)	(6,610)	(7,031)	(7,525)	(8,073)	(8,698)	(9,371)	(10,058)	(10,760)
Net Plant in Service	11,997	12,451	13,310	13,778	18,280	21,138	25,415	25,419	25,400	25,397
Construction in Progress	3,261	4,936	6,759	8,986	6,044	3,943	173	189	245	267
Current and Other Assets	1,350	1,093	1,317	1,744	1,742	2,045	2,277	1,667	1,608	1,810
Goodwill and Intangible Assets	270	258	246	236	236	246	237	221	206	190
Regulated Assets	340	362	398	434	475	495	506	501	484	464
	17,218	19,100	22,030	25,177	26,777	27,867	28,608	27,997	27,942	28,129
LIABILITIES AND EQUITY										
Long-Term Debt	11,722	13,825	16,698	18,706	21,194	21,923	22,809	22,972	23,267	23,458
Current and Other Liabilities	2,086	2,202	2,121	3,053	2,141	2,558	2,590	2,022	1,803	1,855
Contributions in Aid of Construction	436	489	537	587	639	690	740	791	842	894
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2,831	2,901	2,968	3,043	2,968	2,866	2,702	2,510	2,336	2,226
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	17,218	19,100	22,030	25,177	26,777	27,867	28,608	27,997	27,942	28,129
Equity Ratio	23%	19%	17%	16%	15%	14%	13%	12%	11%	11%

CONSOLIDATED PROJECTED BALANCE SHEET (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	36,877	37,639	38,546	39,301	40,080	40,813	41,592	42,389	43,204	44,376
Accumulated Depreciation	(11,478)	(12,211)	(12,960)	(13,728)	(14,510)	(15,303)	(16,110)	(16,933)	(17,773)	(18,629)
Net Plant in Service	25,399	25,428	25,585	25,573	25,570	25,510	25,482	25,456	25,431	25,747
Construction in Progress	326	348	229	258	281	327	369	406	469	259
Current and Other Assets	1,746	2,061	2,354	2,540	2,970	3,321	3,171	3,826	4,496	5,233
Goodwill and Intangible Assets	176	161	148	137	125	114	103	91	80	68
Regulated Assets	438	415	393	367	350	341	336	336	343	347
	28,084	28,413	28,709	28,875	29,295	29,612	29,461	30,116	30,819	31,655
LIABILITIES AND EQUITY										
Long-Term Debt	23,412	24,215	24,418	24,360	24,493	23,766	23,757	23,760	23,754	23,398
Current and Other Liabilities	1,842	1,323	1,267	1,268	1,223	1,797	1,050	984	896	1,189
Contributions in Aid of Construction	947	1,000	1,052	1,105	1,159	1,213	1,268	1,323	1,380	1,437
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2,188	2,179	2,276	2,444	2,724	3,139	3,690	4,352	5,093	5,935
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	28,084	28,413	28,709	28,875	29,295	29,612	29,461	30,116	30,819	31,655
Equity Ratio	11%	11%	12%	13%	14%	16%	18%	21%	24%	27%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	2,368	2,473	2,526	2,631	2,729	2,851	3,234	3,449	3,560	3,696
Cash Paid to Suppliers and Employees	(1,243)	(1,281)	(1,346)	(1,386)	(1,415)	(1,433)	(1,490)	(1,522)	(1,549)	(1,584)
Interest Paid	(528)	(532)	(565)	(613)	(804)	(949)	(1,243)	(1,371)	(1,352)	(1,365)
Interest Received	13	15	21	30	35	34	31	28	15	16
	610	675	636	662	545	503	532	584	674	763
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,983	2,400	3,200	3,200	2,800	1,600	1,600	600	600	600
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(835)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(461)	(300)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,213	2,087	2,846	2,857	2,023	1,470	943	573	263	295
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,951)	(2,586)	(3,187)	(3,281)	(2,289)	(1,588)	(1,050)	(799)	(743)	(741)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(22)	(21)	(21)	(21)	(22)	(36)	(30)	(30)	(30)	(30)
	(2,097)	(2,809)	(3,376)	(3,545)	(2,551)	(1,869)	(1,343)	(1,187)	(1,026)	(1,030)
Net Increase (Decrease) in Cash	(275)	(47)	106	(27)	16	104	132	(30)	(89)	28
Cash at Beginning of Year	142	(133)	(179)	(73)	(100)	(83)	20	152	122	33
Cash at End of Year	(133)	(179)	(73)	(100)	(83)	20	152	122	33	61

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,815	3,865	4,001	4,105	4,237	4,389	4,524	4,615	4,701	4,810
Cash Paid to Suppliers and Employees	(1,610)	(1,623)	(1,648)	(1,665)	(1,690)	(1,715)	(1,738)	(1,767)	(1,790)	(1,822)
Interest Paid	(1,373)	(1,379)	(1,380)	(1,399)	(1,396)	(1,390)	(1,371)	(1,282)	(1,263)	(1,233)
Interest Received	19	21	35	49	62	71	84	63	78	92
	851	884	1,008	1,090	1,213	1,355	1,499	1,630	1,726	1,848
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	400	800	200	-	200	-	-	-	-	-
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(100)	(700)	(13)	(30)	-
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	264	423	171	(27)	175	(22)	(21)	(38)	(37)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(793)	(801)	(803)	(792)	(811)	(794)	(837)	(852)	(899)	(981)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(31)	(31)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(1,094)	(1,101)	(1,106)	(1,109)	(1,140)	(1,134)	(1,184)	(1,177)	(1,235)	(1,329)
Net Increase (Decrease) in Cash	21	206	73	(45)	247	200	293	415	454	483
Cash at Beginning of Year	61	82	288	361	316	563	763	1,056	1,471	1,925
Cash at End of Year	82	288	361	316	563	763	1,056	1,471	1,925	2,408

18.0 CAPITAL EXPENDITURE FORECAST (CEF14)

CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1,448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6,496.1	776.3	676.3	962.2	1,351.3	927.9	616.5	208.6	55.2	4.5	0.1	5,578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1,852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GRE	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1,655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1,514.0
Bipole III - Converter Stations	2,675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2,356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1,451.7**	**1,913.9**	**2,463.5**	**2,577.8**	**1,530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11,670.7**
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Generation Operations Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1,336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishm	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Transmission Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1,350.0**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1,965.3
Customer Service & Distribution Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2,211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5,535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6,103.4**
CONSOLIDATED CEF14 TOTAL		**2,070.6**	**2,555.8**	**3,123.6**	**3,161.5**	**2,113.0**	**1,469.6**	**1,038.7**	**792.8**	**724.1**	**724.4**	**17,774.1**
ELECTRIC CAPITAL TOTAL		**2,022.6**	**2,490.9**	**3,073.1**	**3,125.2**	**2,078.3**	**1,431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17,331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1,448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6,496.1	-	-	-	-	-	-	-	-	-	-	5,578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1,852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GRE	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1,655.4	-	-	-	-	-	-	-	-	-	-	1,514.0
Bipole III - Converter Stations	2,675.1	-	-	-	-	-	-	-	-	-	-	2,356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1,186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12,611.1**
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2,290.6
Generation Operations Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2,900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishm	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2,452.3
Transmission Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3,025.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4,773.2
Customer Service & Distribution Total	**NA**	**261.6**	**257.8**	**263.3**	**267.2**	**285.6**	**268.1**	**298.7**	**297.6**	**302.6**	**305.3**	**5,019.6**
Customer Care & Energy Conservation	**NA**	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**81.0**
Human Resources & Corporate Services	**NA**	**59.5**	**60.7**	**61.9**	**63.2**	**64.4**	**65.7**	**67.0**	**68.4**	**69.8**	**71.1**	**1,248.6**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**4.9**
		621.1	**624.5**	**637.3**	**648.6**	**674.7**	**665.0**	**703.5**	**710.5**	**723.8**	**734.9**	**12,279.9**
Gas												
Customer Service & Distribution	**NA**	**33.7**	**33.5**	**34.0**	**34.7**	**36.6**	**34.1**	**38.2**	**39.3**	**40.2**	**41.0**	**664.1**
Customer Care & Energy Conservation	**NA**	**5.4**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**106.8**
Gas Demand Side Management	**NA**	**9.6**	**9.8**	**10.0**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**165.9**
		48.7	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**669.8**	**673.2**	**686.9**	**694.7**	**722.8**	**710.8**	**753.6**	**761.9**	**776.3**	**788.4**	**13,341.7**
CONSOLIDATED CEF14 TOTAL		**777.6**	**783.9**	**784.7**	**776.0**	**793.3**	**771.5**	**820.1**	**833.5**	**874.7**	**963.4**	**25,952.9**
ELECTRIC CAPITAL TOTAL		**728.9**	**735.1**	**735.1**	**729.9**	**745.3**	**725.7**	**770.0**	**782.2**	**822.2**	**910.0**	**25,016.1**
GAS CAPITAL TOTAL		**48.7**	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**

19.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH14)

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1,437	1,454	1,460	1,483	1,490	1,501	1,506	1,513	1,525	1,538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1,831	1,928	2,008	2,101	2,222	2,352	2,732	2,944	3,054	3,182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1,194	1,326	1,334	1,349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1,754	1,824	1,956	2,044	2,317	2,471	2,920	3,150	3,239	3,304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1,551	1,565	1,580	1,593	1,607	1,624	1,641	1,659	1,677	1,696
additional*	734	832	935	1,043	1,157	1,280	1,409	1,486	1,566	1,649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3,298	3,342	3,475	3,575	3,702	3,849	3,980	4,065	4,145	4,248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1,351	1,348	1,338	1,337	1,321	1,301	1,263	1,197	1,161	1,116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3,346	3,365	3,388	3,415	3,430	3,439	3,432	3,403	3,403	3,404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,163	17,912	19,127	19,988	24,957	28,333	33,202	33,846	34,478	35,142
Accumulated Depreciation	(5,676)	(6,012)	(6,392)	(6,795)	(7,270)	(7,798)	(8,403)	(9,055)	(9,721)	(10,401)
Net Plant in Service	11,487	11,900	12,735	13,193	17,687	20,535	24,800	24,791	24,757	24,741
Construction in Progress	3,257	4,932	6,755	8,982	6,040	3,939	169	185	241	263
Current and Other Assets	1,798	1,570	1,822	2,268	2,295	2,598	2,727	2,167	2,238	2,442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965
LIABILITIES AND EQUITY										
Long-Term Debt	11,705	13,808	16,681	18,689	21,177	21,906	22,792	22,955	23,250	23,441
Current and Other Liabilities	2,016	2,151	2,097	3,069	2,214	2,654	2,604	2,104	2,028	2,101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2,717	2,778	2,837	2,902	2,812	2,696	2,518	2,312	2,126	2,001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35,822	36,544	37,410	38,124	38,859	39,555	40,294	41,050	41,823	42,952
Accumulated Depreciation	(11,096)	(11,807)	(12,532)	(13,274)	(14,030)	(14,800)	(15,585)	(16,384)	(17,200)	(18,031)
Net Plant in Service	24,725	24,737	24,878	24,849	24,828	24,754	24,710	24,666	24,623	24,921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2,387	2,536	2,801	3,049	3,421	3,773	3,629	4,288	4,963	5,703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189
LIABILITIES AND EQUITY										
Long-Term Debt	23,395	24,198	24,401	24,343	24,476	23,749	23,739	23,743	23,737	23,381
Current and Other Liabilities	2,112	1,443	1,373	1,456	1,372	1,968	1,243	1,199	1,132	1,446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1,029	1,069	1,109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1,948	1,924	2,007	2,161	2,427	2,826	3,361	4,008	4,732	5,557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,859	1,958	2,039	2,134	2,231	2,349	2,729	2,941	3,051	3,180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1,000)	(1,015)	(1,069)	(1,099)	(1,124)	(1,155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1,222)	(1,349)	(1,329)	(1,341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,953	2,390	3,190	3,200	2,790	1,600	1,590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,218	2,077	2,836	2,857	2,013	1,470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,900)	(2,518)	(3,134)	(3,244)	(2,253)	(1,550)	(1,010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2,046)	(2,742)	(3,323)	(3,508)	(2,516)	(1,830)	(1,302)	(1,144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,295	3,340	3,472	3,572	3,699	3,846	3,977	4,062	4,142	4,245
Cash Paid to Suppliers and Employees	(1,179)	(1,189)	(1,211)	(1,225)	(1,247)	(1,269)	(1,288)	(1,314)	(1,334)	(1,363)
Interest Paid	(1,348)	(1,353)	(1,354)	(1,371)	(1,368)	(1,360)	(1,341)	(1,250)	(1,230)	(1,200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1,024	1,146	1,288	1,432	1,561	1,655	1,775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,045)	(1,051)	(1,056)	(1,062)	(1,091)	(1,087)	(1,134)	(1,125)	(1,182)	(1,275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1,390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1,390	1,844

20.0 GAS OPERATIONS FINANCIAL FORECAST (CGM14)

GAS OPERATIONS (CGM14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	423	393	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	423	393	401	405	407	409	410	410	416
Cost of Gas Sold	270	277	247	247	246	247	247	248	247	247
Gross Margin	149	147	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	148	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	21	22	22	23	24	25
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	152	154	157	157	160	162	167
Net Income	7	4	0	3	7	5	6	4	2	4
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%

GAS OPERATIONS (CGM14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	310	320	320	330	330	340	320	350	370
Current and Other Liabilities	130	137	137	126	97	84	64	76	43	15
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	72	72	75	82	87	93	97	99	102
	684	723	748	756	762	770	780	792	806	817

GAS OPERATIONS (CGM14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	461	430	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(25)
	25	61	37	35	34	33	33	32	29	33
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	10	10	-	10	-	10	-	40	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	10	10	-	10	-	10	-	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	6	(4)	(2)	8	(6)	2	(11)	4	(1)
Cash at Beginning of Year	(34)	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)
Cash at End of Year	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)	(69)

21.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS14)

CORPORATE SUBSIDIARIES (CS14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
Revenue	53	55	57	58	59	60	62	63	64	66
Cost of Operations	29	30	31	32	32	33	34	35	35	36
	23	24	26	26	27	27	28	29	29	30
EXPENSES										
Operating and Administrative	15	16	16	16	17	17	17	17	17	18
Finance Expense	(0)	(0)	(0)	-	-	-	-	-	-	-
Depreciation and Amortization	1	2	2	2	2	2	1	1	1	0
Capital and Other Taxes	1	1	1	1	1	1	1	1	1	1
	17	18	19	19	19	19	19	19	19	19
Net Income	6	6	7	8	8	8	9	9	10	11

CORPORATE SUBSIDIARIES (CS14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	16	17	19	19	19	19	19	19	19	19
Accumulated Depreciation	(5)	(7)	(9)	(10)	(12)	(13)	(15)	(16)	(17)	(17)
Net Plant in Service	10	10	10	8	7	5	4	2	2	2
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	44	50	58	67	76	86	97	108	119	130
Goodwill and Intangible Assets	1	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Regulated Assets	0	0	0	0	0	0	0	0	0	0
	54	61	68	75	83	92	101	110	120	132
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	7	7	7	7	7	7	7	7	7	7
Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0
Share Captial	1	1	1	1	1	1	1	1	1	1
Retained Earnings	46	52	59	67	74	83	92	101	112	123
	54	61	68	75	83	92	101	110	120	132

CORPORATE SUBSIDIARIES (CS14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	53	55	57	58	59	60	62	63	64	66
Cash Paid to Suppliers and Employees	(45)	(47)	(48)	(49)	(50)	(51)	(51)	(52)	(53)	(54)
Interest Paid	0	0	0	-	-	-	-	-	-	-
	7	8	9	9	10	10	10	11	11	11
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1)	(2)	(1)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(1)	(2)	(1)	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	6	6	8	9	10	10	10	11	11	11
Cash at Beginning of Year	9	15	21	29	38	48	58	68	79	90
Cash at End of Year	15	21	29	38	48	58	68	79	90	101

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
GCR at Approved Rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
Proposed Rate Increases	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 334	1 349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 956	2 044	2 317	2 471	2 920	3 150	3 239	3 304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.16	1.07	1.06	0.92	0.91	0.86	0.85	0.86	0.91
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
GCR at Approved Rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
Proposed Rate Increases	734	832	935	1 043	1 157	1 280	1 409	1 486	1 566	1 649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 298	3 342	3 475	3 575	3 702	3 849	3 980	4 065	4 145	4 248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 351	1 348	1 338	1 337	1 321	1 301	1 263	1 197	1 161	1 116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 346	3 365	3 388	3 415	3 430	3 439	3 432	3 403	3 403	3 404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
Capital Coverage	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 727	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 097	3 069	2 214	2 654	2 604	2 104	2 028	2 101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 837	2 902	2 812	2 696	2 518	2 312	2 126	2 001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 387	2 536	2 801	3 049	3 421	3 773	3 629	4 288	4 963	5 703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189
LIABILITIES AND EQUITY										
Long-Term Debt	23 395	24 198	24 401	24 343	24 476	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 112	1 443	1 373	1 456	1 372	1 968	1 243	1 199	1 132	1 446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 948	1 924	2 007	2 161	2 427	2 826	3 361	4 008	4 732	5 557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 349)	(1 329)	(1 341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 295	3 340	3 472	3 572	3 699	3 846	3 977	4 062	4 142	4 245
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 348)	(1 353)	(1 354)	(1 371)	(1 368)	(1 360)	(1 341)	(1 250)	(1 230)	(1 200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1 024	1 146	1 288	1 432	1 561	1 655	1 775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 051)	(1 056)	(1 062)	(1 091)	(1 087)	(1 134)	(1 125)	(1 182)	(1 275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1 390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1 390	1 844

APPENDIX 3.5: ALTERNATE RATE SCENARIOS

The 3.95% proposed and indicative rate increases in MH14 are the minimum necessary to manage the significant deterioration in Manitoba Hydro's projected financial results and ratios in the next 10 year period and are vital to rate stability for customers and the continued financial strength of Manitoba Hydro.

Figure 3.5.1 shows the impacts to key financial indicators at the end of the 10 year period in 2023/24 for alternate rate scenarios without the proposed and indicative 3.95% rate increases (Scenario A), with rate increases limited to inflationary adjustments (Scenario B), rate increases deferred to future periods (Scenarios C-F)**,** as well as higher near term rate increases to mitigate losses over the 10 year period and reduce future rate increases (Scenarios G-I).

Figure 3.5.1: Financial Impacts of Alternate Rate Increases by 2023/24

Projected Rate Increases	Retained Earnings ($Billions)	Debt to Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
MH14- 3.95% 2016-2024	$2.0	90:10	0.91	1.22
A. 0.00% -2016-2024	($1.5)	104:(4)	0.39	(0.20)
B. 2.00% -2016-2024	$0.2	98:2	0.62	0.47
C. 2.00% -2016-2019, 3.95% thereafter	$0.7	95:5	0.76	0.84
D. 2.95% -2016-2019, 3.95% thereafter	$1.3	93:7	0.83	1.02
E. 2.00% -2016-2019, 7.94% thereafter	$2.0	90:10	1.09	1.66
F. 2.95% -2016-2019, 6.00% thereafter	$2.0	90:10	1.00	1.45
G. 5.00% -2016-2019, 3.00% thereafter	$2.4	89:11	0.92	1.24
H. 5.50% -2016-2019, 3.00% thereafter	$2.7	88:12	0.96	1.35
I. 6.00% -2016-2019, 3.00% thereafter	$3.1	86:14	1.00	1.45

The financial projections for each of the above alternate rate scenarios can be found in Attachments A to I of this appendix.

Scenario A in Figure 3.5.1 shows that without the 3.95% proposed and indicative rate increases throughout the 10 year forecast period to 2023/24, the Corporation's financial reserves would be totally depleted by 2022/23.

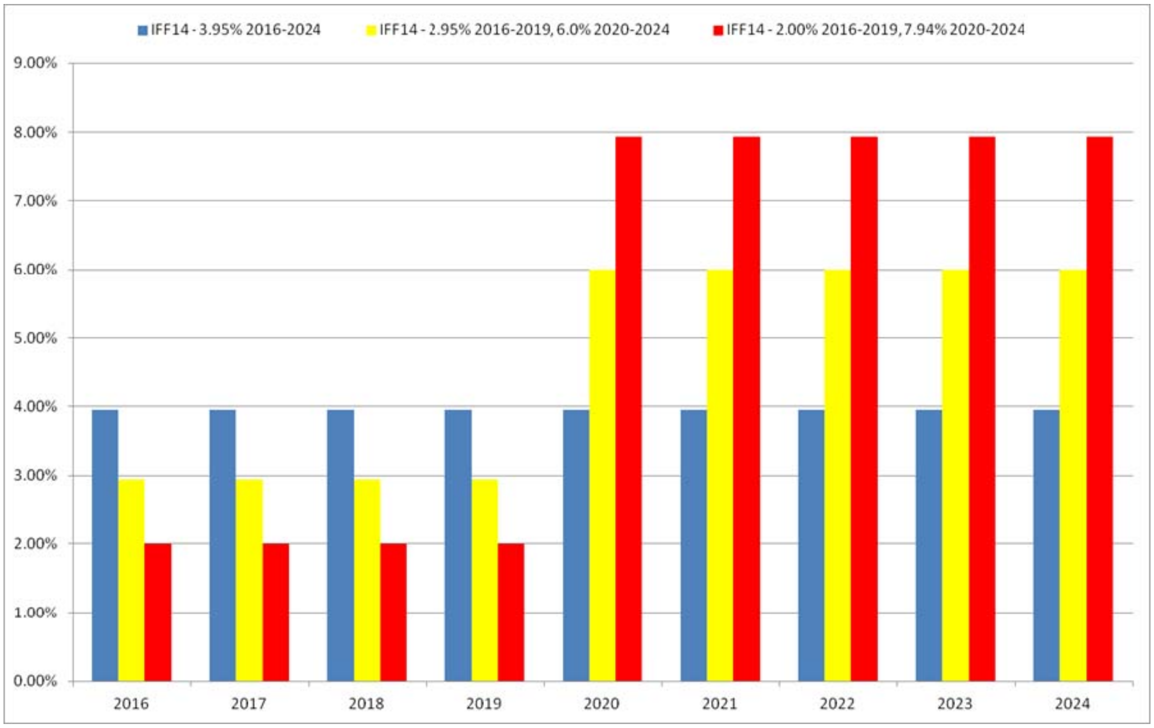
In Scenario B the rate increases are limited to inflationary levels (around 2%) over the 10 year forecast, Manitoba Hydro's assets are almost fully funded by debt and financial reserves are nearly completely depleted. The very weak interest coverage and capital coverage ratios indicate that the Corporation’s cash flow is negative and the shortfall is funded through increased borrowing. Under Scenario B, it is clear that the 2% rate increases cannot be sustained for a prolonged period of time.

Scenarios C and D assume reductions to the proposed and indicative rate increases of 3.95% in the first four years (2016-2019) to 2.0% and 2.95%, with no compensating rate increases in the period following the rate reductions (2020-2024). In these scenarios, the Corporation’s financial ratios and reserves deteriorate to unacceptable levels. Retained earnings deteriorate to a level that are significantly lower than the projected $1.7 billion cost of a five year drought. The projected equity ratio deteriorates to unacceptable levels of 5% and 7% by 2023/24 for Scenarios C and D, respectively. The projected interest coverage ratio under Scenario C is below 1.00 in all but the first two years of the ten year forecast period. Under Scenario D, the projected interest coverage is below 1.00 for the last six years of the ten year forecast period. Similarly, the projected capital coverage ratio is below 1.00 for most forecast years under both Scenarios C and D.

This level of deterioration indicates that projected cash flows under Scenarios C and D, are not sufficient to fund Manitoba Hydro’s operations or sustaining capital program and result in incremental borrowing at an unsustainable rate. Customers would be at significant risk of a rate shock, particularly if a drought or catastrophic infrastructure loss occurred.

In Scenarios E and F, Manitoba Hydro calculates the compensating rate increases that are required in the five year period from 2020 to 2024 associated with rate increases of 2.0% and 2.95% for the four year period from 2016 to 2019. Figure 3.5.2 below demonstrates that with 2% rate increases for the next 4 years, Manitoba Hydro would require 8% rate increases for the following five years (Scenario E), and with 2.95% rate increases for the next four years, Manitoba Hydro would require 6% rate increases in the five years that follow (Scenario F). This analysis demonstrates how future rate increases would have to increase, to compensate for lower rate increases obtained in the near-term.

Figure 3.5.2: Projected Rate Increase Scenarios



Considering the financial outlook as projected in MH14, there is financial justification for requesting rate increases in excess of 3.95%. In Scenarios G, H and I, Manitoba Hydro analyzed other alternate rate scenarios that involve higher rate increases.

Higher rate increases in the near term would assist in reducing the losses that are projected in the next 10 year period. This alleviates some of the downward pressure on the Corporation's projected financial ratios in the investment period and the risk of the significantly higher rate increases in the future in the event of a significant drought or other adverse financial conditions. Rate increases in the 5.50-6.0% level for the next four years (2016-2019) would be necessary to reduce losses and maintain financial reserves at current levels, and result in lower rate increases of 3.0% for the 2020-2024 period.

Despite the increased risk of higher than projected rate increases in the future, Manitoba Hydro has maintained the proposed rate increases at the 3.95% level in consideration of customer sensitivity to rate increases.

In order to ensure rate stability and predictability for customers, it is necessary that Manitoba Hydro maintains its financial strength. If Manitoba Hydro does not maintain a financially healthy utility by maintaining moderate and regular rate increases as proposed and projected, then there is significant risk to customers that rate changes will become more volatile. Consequently, there would be a need for sudden or larger rate increases in the near future. This risk is particularly acute in the upcoming period of extensive capital investment and reinvestment.

It is of vital importance that the rate increases be regular and occur even when there are short-term favorable water flow conditions in order to ensure rate stability and predictability for customers. In Manitoba Hydro’s view, gradually raising rates by the minimum 3.95% rate increases is in the customer’s best interest.

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 0% RATE INCREASES (2016-2024)

PROJECTED OPERATING STATEMENT

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	0	0	0	0	0	0	0	0	0
BPIII Reserve Account	(30)	(31)	(31)	(32)	(9)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 871	1 893	1 922	1 974	2 031	2 338	2 472	2 500	2 541
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	553	596	778	932	1 264	1 425	1 467	1 526
Depreciation and Amortization	405	401	422	445	521	527	616	670	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	142	141	144	141	160
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 962	2 058	2 344	2 518	2 990	3 246	3 364	3 480
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	58	(61)	(129)	(364)	(484)	(642)	(773)	(865)	(942)
* Additional General Consumers Revenue										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity	22%	18%	15%	14%	11%	9%	7%	3%	-1%	-4%
Interest Coverage	1.16	1.08	0.93	0.88	0.69	0.62	0.53	0.46	0.42	0.39
Capital Coverage	0.98	0.92	0.74	0.74	0.38	0.15	0.03	(0.06)	(0.11)	(0.20)

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 0% RATE INCREASES (2016-2024)
PROJECTED BALANCE SHEET

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 823	2 268	2 299	2 605	2 738	2 175	2 258	2 470
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 589	27 675	28 309	27 735	27 808	27 993
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 881	19 089	21 777	22 906	24 192	24 955	26 050	27 041
Current and Other Liabilities	2 016	2 209	2 079	3 047	2 272	2 680	2 694	2 157	1 970	2 069
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	80	111	143	152	101	51	-	-	-
Retained Earnings	2 717	2 721	2 660	2 531	2 167	1 683	1 041	268	(597)	(1 539)
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 589	27 675	28 309	27 735	27 808	27 993

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 0% RATE INCREASES (2016-2024)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 900	1 922	1 951	1 981	2 028	2 335	2 470	2 497	2 538
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 013)	(1 065)	(1 092)	(1 114)	(1 155)
Interest Paid	(511)	(514)	(547)	(603)	(806)	(969)	(1 285)	(1 442)	(1 461)	(1 513)
Interest Received	13	15	21	30	35	35	31	29	15	16
	558	529	453	406	210	80	15	(36)	(62)	(114)
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 390	3 400	2 990	2 000	1 990	1 200	1 360	1 380
Sinking Fund Withdrawals	110	21	-	8	448	208	300	718	173	47
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	3 036	3 058	2 213	1 874	1 339	1 175	1 051	1 105
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(245)	(252)	(273)	(358)	(273)	(286)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 324)	(3 508)	(2 520)	(1 837)	(1 312)	(1 144)	(1 001)	(1 014)
Net Increase (Decrease) in Cash	(270)	(135)	166	(44)	(97)	117	42	(5)	(13)	(22)
Cash at Beginning of Year	133	(137)	(272)	(106)	(151)	(247)	(130)	(88)	(93)	(105)
Cash at End of Year	(137)	(272)	(106)	(151)	(247)	(130)	(88)	(93)	(105)	(127)

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 2% RATE INCREASES (2016-2024)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	29	59	91	123	156	190	225	262	300
BPIII Reserve Account	(30)	(32)	(33)	(34)	(10)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 900	1 950	2 011	2 096	2 187	2 528	2 697	2 762	2 841
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	550	588	765	910	1 229	1 376	1 402	1 441
Depreciation and Amortization	405	401	422	445	521	526	614	668	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	143	143	147	146	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 959	2 051	2 331	2 495	2 955	3 199	3 303	3 395
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	87	(1)	(33)	(229)	(304)	(417)	(501)	(542)	(557)
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%
Financial Ratios										
Equity	22%	18%	16%	14%	13%	11%	9%	6%	4%	2%
Interest Coverage	1.16	1.12	1.00	0.97	0.80	0.76	0.69	0.64	0.62	0.62
Capital Coverage	0.98	0.97	0.84	0.91	0.63	0.46	0.41	0.42	0.46	0.47

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2% RATE INCREASES (2016-2024)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 297	2 601	2 733	2 170	2 248	2 456
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 587	27 672	28 304	27 730	27 798	27 980
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 889	21 577	22 306	23 392	23 955	24 650	25 241
Current and Other Liabilities	2 016	2 180	2 187	3 058	2 145	2 774	2 763	2 155	2 041	2 151
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	113	147	157	105	52	-	-	-
Retained Earnings	2 717	2 750	2 749	2 716	2 487	2 183	1 765	1 265	722	165
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 587	27 672	28 304	27 730	27 798	27 980

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2% RATE INCREASES (2016-2024)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 929	1 981	2 042	2 104	2 184	2 525	2 695	2 759	2 838
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 014)	(1 067)	(1 096)	(1 119)	(1 155)
Interest Paid	(511)	(514)	(547)	(599)	(796)	(951)	(1 252)	(1 396)	(1 396)	(1 428)
Interest Received	13	15	21	30	35	35	31	29	15	16
	558	559	512	501	343	254	237	232	259	271
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 400	2 990	1 600	1 790	1 000	960	980
Sinking Fund Withdrawals	110	21	-	8	448	206	297	718	168	37
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	3 057	2 213	1 472	1 136	975	646	695
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(243)	(249)	(268)	(358)	(263)	(273)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 518)	(1 834)	(1 307)	(1 144)	(991)	(1 000)
Net Increase (Decrease) in Cash	(270)	(106)	25	50	38	(108)	66	63	(86)	(34)
Cash at Beginning of Year	133	(137)	(243)	(218)	(168)	(129)	(238)	(172)	(109)	(195)
Cash at End of Year	(137)	(243)	(218)	(168)	(129)	(238)	(172)	(109)	(195)	(229)

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 2.00% for 4 years (2016-2019)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	1,437	1,454	1,460	1,483	1,490	1,501	1,506	1,513	1,525	1,538
additional*	0	29	59	91	123	188	255	327	403	482
BPIII Reserve Account	(30)	(32)	(33)	(34)	(10)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1,831	1,900	1,950	2,011	2,096	2,219	2,593	2,799	2,902	3,023
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	550	588	765	910	1,225	1,367	1,387	1,414
Depreciation and Amortization	405	401	422	445	521	526	614	668	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	143	143	148	147	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1,754	1,825	1,959	2,051	2,331	2,494	2,952	3,191	3,289	3,369
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	87	(1)	(33)	(229)	(272)	(349)	(392)	(388)	(348)
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.00%	2.00%	2.00%	2.00%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	2.00%	4.04%	6.12%	8.24%	12.52%	16.96%	21.58%	26.39%	31.38%
Financial Ratios										
Equity	22%	18%	16%	14%	13%	11%	10%	7%	6%	5%
Interest Coverage	1.16	1.12	1.00	0.97	0.80	0.78	0.74	0.72	0.72	0.76
Capital Coverage	0.98	0.97	0.84	0.91	0.63	0.52	0.53	0.61	0.73	0.84

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.00% for 4 years (2016-2019)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,163	17,912	19,127	19,988	24,957	28,333	33,202	33,846	34,478	35,142
Accumulated Depreciation	(5,676)	(6,012)	(6,392)	(6,795)	(7,270)	(7,798)	(8,403)	(9,055)	(9,721)	(10,401)
Net Plant in Service	11,487	11,900	12,735	13,193	17,687	20,535	24,800	24,791	24,757	24,741
Construction in Progress	3,257	4,932	6,755	8,982	6,040	3,939	169	185	241	263
Current and Other Assets	1,798	1,570	1,822	2,268	2,297	2,601	2,732	2,170	2,246	2,452
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16,993	18,866	21,801	24,961	26,587	27,672	28,304	27,730	27,796	27,976
LIABILITIES AND EQUITY										
Long-Term Debt	11,705	13,808	16,681	18,889	21,577	22,306	23,392	23,755	24,250	24,841
Current and Other Liabilities	2,016	2,180	2,187	3,058	2,145	2,742	2,662	2,145	2,075	1,975
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	113	147	157	105	52	-	-	-
Retained Earnings	2,717	2,750	2,749	2,716	2,487	2,215	1,866	1,474	1,086	738
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16,993	18,866	21,801	24,961	26,587	27,672	28,304	27,730	27,796	27,976

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.00% for 4 years (2016-2019)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,859	1,929	1,981	2,042	2,104	2,216	2,590	2,796	2,900	3,021
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1,000)	(1,014)	(1,067)	(1,097)	(1,120)	(1,155)
Interest Paid	(511)	(514)	(547)	(599)	(796)	(951)	(1,252)	(1,391)	(1,382)	(1,402)
Interest Received	13	15	21	30	35	35	31	28	15	16
	558	559	512	501	343	286	302	337	412	479
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,953	2,390	3,190	3,400	2,990	1,600	1,790	800	760	980
Sinking Fund Withdrawals	110	21	-	8	448	206	297	718	168	35
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,218	2,077	2,836	3,057	2,213	1,472	1,136	775	445	693
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,900)	(2,518)	(3,134)	(3,244)	(2,253)	(1,550)	(1,010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(243)	(249)	(267)	(358)	(261)	(269)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2,046)	(2,742)	(3,323)	(3,508)	(2,518)	(1,834)	(1,307)	(1,144)	(989)	(996)
Net Increase (Decrease) in Cash	(270)	(106)	25	50	38	(76)	131	(32)	(132)	176
Cash at Beginning of Year	133	(137)	(243)	(218)	(168)	(129)	(205)	(74)	(106)	(238)
Cash at End of Year	(137)	(243)	(218)	(168)	(129)	(205)	(74)	(106)	(238)	(62)

ELECTRIC OPERATIONS

ALTERNATE RATE SCENARIO - 2.95% for 4 years (2016-2019)

PROJECTED OPERATING STATEMENT

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1,437	1,454	1,460	1,483	1,490	1,501	1,506	1,513	1,525	1,538
additional*	0	43	87	135	184	252	322	396	475	559
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1,831	1,913	1,978	2,054	2,157	2,282	2,660	2,869	2,975	3,100
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	549	586	759	899	1,210	1,347	1,361	1,383
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	149	149	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1,754	1,825	1,958	2,048	2,324	2,483	2,937	3,171	3,265	3,337
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	101	28	13	(162)	(197)	(267)	(302)	(291)	(241)
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.95%	2.95%	2.95%	2.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	2.95%	5.99%	9.11%	12.33%	16.77%	21.38%	26.18%	31.16%	36.34%
Financial Ratios										
Equity	22%	18%	16%	15%	13%	12%	11%	9%	8%	7%
Interest Coverage	1.16	1.14	1.03	1.01	0.86	0.84	0.80	0.78	0.79	0.83
Capital Coverage	0.98	0.99	0.89	1.01	0.74	0.66	0.68	0.78	0.90	1.02

ELECTRIC OPERATIONS
ALTERNATE RATE SCENARIO - 2.95% for 4 years (2016-2019)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17,163	17,912	19,127	19,988	24,957	28,333	33,202	33,846	34,478	35,142
Accumulated Depreciation	(5,676)	(6,012)	(6,392)	(6,795)	(7,270)	(7,798)	(8,403)	(9,055)	(9,721)	(10,401)
Net Plant in Service	11,487	11,900	12,735	13,193	17,687	20,535	24,800	24,791	24,757	24,741
Construction in Progress	3,257	4,932	6,755	8,982	6,040	3,939	169	185	241	263
Current and Other Assets	1,798	1,570	1,822	2,268	2,296	2,600	2,730	2,167	2,242	2,447
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16,993	18,866	21,801	24,961	26,586	27,670	28,301	27,728	27,792	27,971
LIABILITIES AND EQUITY										
Long-Term Debt	11,705	13,808	16,681	18,889	21,377	22,106	22,992	23,355	23,850	24,241
Current and Other Liabilities	2,016	2,166	2,144	2,968	2,186	2,708	2,747	2,141	1,973	1,964
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	149	159	106	53	-	-	-
Retained Earnings	2,717	2,763	2,791	2,805	2,643	2,446	2,178	1,876	1,585	1,344
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16,993	18,866	21,801	24,961	26,586	27,670	28,301	27,728	27,792	27,971

ELECTRIC OPERATIONS
ALTERNATE RATE SCENARIO - 2.95% for 4 years (2016-2019)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,859	1,943	2,009	2,087	2,165	2,280	2,657	2,866	2,972	3,097
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1,000)	(1,014)	(1,068)	(1,098)	(1,122)	(1,155)
Interest Paid	(511)	(514)	(546)	(592)	(795)	(939)	(1,233)	(1,367)	(1,357)	(1,375)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	573	541	552	406	361	387	430	509	583
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,953	2,390	3,190	3,400	2,790	1,600	1,590	800	760	780
Sinking Fund Withdrawals	110	21	-	8	448	205	295	718	165	31
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,218	2,077	2,836	3,057	2,013	1,471	935	775	443	489
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,900)	(2,518)	(3,134)	(3,244)	(2,253)	(1,550)	(1,010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(247)	(265)	(358)	(256)	(264)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2,046)	(2,742)	(3,323)	(3,508)	(2,517)	(1,832)	(1,305)	(1,144)	(985)	(991)
Net Increase (Decrease) in Cash	(270)	(92)	54	101	(98)	(0)	17	61	(33)	80
Cash at Beginning of Year	133	(137)	(229)	(175)	(74)	(172)	(172)	(156)	(95)	(128)
Cash at End of Year	(137)	(229)	(175)	(74)	(172)	(172)	(156)	(95)	(128)	(47)

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 2.00% (2016-2019), 7.94% thereafter

PROJECTED OPERATING STATEMENT

(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	29	59	91	123	253	393	547	716	901
BPIII Reserve Account	(30)	(32)	(33)	(34)	(10)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 900	1 950	2 011	2 096	2 283	2 731	3 019	3 216	3 442
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	550	588	765	908	1 219	1 350	1 354	1 358
Depreciation and Amortization	405	401	422	445	521	526	614	668	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	150	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 959	2 051	2 331	2 493	2 947	3 176	3 260	3 312
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	87	(1)	(33)	(229)	(206)	(205)	(156)	(45)	127
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.00%	2.00%	2.00%	2.00%	7.94%	7.94%	7.94%	7.94%	7.94%
Cumulative Percent Increase	0.00%	2.00%	4.04%	6.12%	8.24%	16.84%	26.12%	36.14%	46.95%	58.62%
Financial Ratios										
Equity	22%	18%	16%	14%	13%	12%	11%	9%	9%	10%
Interest Coverage	1.16	1.12	1.00	0.97	0.80	0.84	0.85	0.89	0.97	1.09
Capital Coverage	0.98	0.97	0.84	0.91	0.63	0.65	0.78	1.03	1.34	1.66

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.00% (2016-2019), 7.94% thereafter
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 297	2 601	2 732	2 169	2 241	2 444
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 587	27 672	28 303	27 729	27 792	27 968
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 889	21 577	22 306	23 192	23 355	23 650	23 441
Current and Other Liabilities	2 016	2 180	2 187	3 058	2 145	2 675	2 652	2 099	1 882	2 104
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	113	147	157	105	52	-	-	-
Retained Earnings	2 717	2 750	2 749	2 716	2 487	2 281	2 076	1 920	1 875	2 001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 587	27 672	28 303	27 729	27 792	27 968

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.00% (2016-2019), 7.94% thereafter
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 929	1 981	2 042	2 104	2 281	2 728	3 017	3 213	3 440
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 014)	(1 068)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(547)	(599)	(796)	(946)	(1 245)	(1 374)	(1 350)	(1 354)
Interest Received	13	15	21	30	35	35	31	28	15	16
	558	559	512	501	343	355	446	573	755	946
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 400	2 990	1 600	1 590	600	560	180
Sinking Fund Withdrawals	110	21	-	8	448	206	297	718	167	30
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	3 057	2 213	1 472	936	575	245	(112)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(243)	(249)	(267)	(358)	(256)	(261)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 518)	(1 834)	(1 306)	(1 144)	(984)	(988)
Net Increase (Decrease) in Cash	(270)	(106)	25	50	38	(6)	76	4	15	(154)
Cash at Beginning of Year	133	(137)	(243)	(218)	(168)	(129)	(136)	(60)	(56)	(41)
Cash at End of Year	(137)	(243)	(218)	(168)	(129)	(136)	(60)	(56)	(41)	(194)

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.95% (2016-2019), 6% thereafter
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	43	87	135	184	286	395	511	638	774
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 913	1 978	2 054	2 157	2 317	2 732	2 984	3 138	3 315
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	549	586	759	898	1 206	1 338	1 344	1 354
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 958	2 048	2 324	2 482	2 934	3 163	3 250	3 308
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	101	28	13	(162)	(162)	(191)	(179)	(113)	3
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.95%	2.95%	2.95%	2.95%	6.00%	6.00%	6.00%	6.00%	6.00%
Cumulative Percent Increase	0.00%	2.95%	5.99%	9.11%	12.33%	19.07%	26.22%	33.79%	41.81%	50.32%
Financial Ratios										
Equity	22%	18%	16%	15%	13%	12%	11%	10%	9%	10%
Interest Coverage	1.16	1.14	1.03	1.01	0.86	0.87	0.86	0.87	0.92	1.00
Capital Coverage	0.98	0.99	0.89	1.01	0.74	0.72	0.80	0.99	1.22	1.45

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.95% (2016-2019), 6% thereafter
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 600	2 730	2 167	2 240	2 443
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 670	28 301	27 727	27 790	27 967
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 889	21 377	22 106	22 992	23 155	23 450	23 441
Current and Other Liabilities	2 016	2 166	2 144	2 968	2 186	2 672	2 635	2 105	1 957	2 102
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	149	159	106	53	-	-	-
Retained Earnings	2 717	2 763	2 791	2 805	2 643	2 481	2 290	2 111	1 998	2 001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 670	28 301	27 727	27 790	27 967

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 2.95% (2016-2019), 6% thereafter
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 943	2 009	2 087	2 165	2 314	2 730	2 981	3 135	3 312
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(546)	(592)	(795)	(939)	(1 234)	(1 361)	(1 340)	(1 346)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	573	541	552	406	395	458	549	687	827
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 400	2 790	1 600	1 590	600	560	380
Sinking Fund Withdrawals	110	21	-	8	448	205	295	718	165	28
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	3 057	2 013	1 471	935	575	243	86
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(247)	(265)	(358)	(254)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 517)	(1 832)	(1 304)	(1 144)	(982)	(987)
Net Increase (Decrease) in Cash	(270)	(92)	54	101	(98)	34	88	(20)	(53)	(74)
Cash at Beginning of Year	133	(137)	(229)	(175)	(74)	(172)	(138)	(50)	(70)	(123)
Cash at End of Year	(137)	(229)	(175)	(74)	(172)	(138)	(50)	(70)	(123)	(196)

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 5.00% (2016-2019), 3.00% thereafter

PROJECTED OPERATING STATEMENT

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	73	150	234	321	378	436	497	561	629
BPIII Reserve Account	(30)	(33)	(34)	(37)	(12)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 942	2 039	2 151	2 293	2 409	2 774	2 969	3 061	3 170
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	546	578	744	874	1 178	1 306	1 312	1 326
Depreciation and Amortization	405	401	422	445	521	523	612	666	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 954	2 040	2 309	2 458	2 904	3 130	3 219	3 281
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	131	93	118	(11)	(45)	(120)	(160)	(158)	(114)
* Additional General Consumers Revenue										
Percent Increase	0.00%	5.00%	5.00%	5.00%	5.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Cumulative Percent Increase	0.00%	5.00%	10.25%	15.76%	21.55%	25.20%	28.95%	32.82%	36.81%	40.91%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	14%	13%	12%	11%	11%
Interest Coverage	1.16	1.18	1.11	1.12	0.99	0.96	0.91	0.88	0.88	0.92
Capital Coverage	0.98	1.04	1.00	1.19	1.02	0.93	0.91	1.02	1.14	1.24

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 5.00% (2016-2019), 3.00% thereafter
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 596	2 726	2 167	2 234	2 438
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 584	27 667	28 298	27 727	27 784	27 961
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	20 977	21 706	22 392	22 555	22 850	23 041
Current and Other Liabilities	2 016	2 135	2 047	2 965	2 229	2 598	2 692	2 149	2 041	2 103
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	82	116	153	164	110	55	-	-	-
Retained Earnings	2 717	2 793	2 886	3 004	2 993	2 948	2 828	2 667	2 509	2 395
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 584	27 667	28 298	27 727	27 784	27 961

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 5.00% (2016-2019), 3.00% thereafter
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 973	2 071	2 185	2 302	2 406	2 771	2 966	3 059	3 167
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 100)	(1 125)	(1 155)
Interest Paid	(511)	(514)	(543)	(592)	(779)	(917)	(1 208)	(1 329)	(1 308)	(1 318)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	602	607	650	559	509	524	566	641	710
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 590	1 600	1 390	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	203	292	715	165	23
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	1 813	1 469	731	572	243	281
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(243)	(261)	(358)	(249)	(254)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 515)	(1 828)	(1 301)	(1 144)	(977)	(982)
Net Increase (Decrease) in Cash	(270)	(62)	120	(1)	(143)	149	(46)	(6)	(93)	9
Cash at Beginning of Year	133	(137)	(199)	(79)	(80)	(223)	(74)	(120)	(126)	(219)
Cash at End of Year	(137)	(199)	(79)	(80)	(223)	(74)	(120)	(126)	(219)	(210)

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 5.50% (2016-2019), 3.00% thereafter
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	80	165	258	356	414	473	535	602	671
BPIII Reserve Account	(30)	(33)	(35)	(37)	(12)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 950	2 054	2 175	2 328	2 445	2 811	3 008	3 101	3 212
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	545	576	741	869	1 169	1 295	1 298	1 309
Depreciation and Amortization	405	401	422	445	521	523	611	665	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	152	152	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 954	2 038	2 306	2 452	2 895	3 119	3 206	3 264
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	138	108	143	27	(3)	(74)	(111)	(106)	(55)
* Additional General Consumers Revenue										
Percent Increase	0.00%	5.50%	5.50%	5.50%	5.50%	3.00%	3.00%	3.00%	3.00%	3.00%
Cumulative Percent Increase	0.00%	5.50%	11.30%	17.42%	23.88%	27.60%	31.43%	35.37%	39.43%	43.61%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	15%	14%	13%	13%	12%
Interest Coverage	1.16	1.19	1.13	1.14	1.02	1.00	0.94	0.92	0.92	0.96
Capital Coverage	0.98	1.06	1.02	1.24	1.09	1.00	0.99	1.11	1.23	1.35

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 5.50% (2016-2019), 3.00% thereafter
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 595	2 726	2 167	2 232	2 435
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 782	27 958
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 192	22 355	22 650	22 841
Current and Other Liabilities	2 016	2 128	2 224	3 115	2 142	2 669	2 718	2 126	1 963	1 966
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	82	116	154	166	110	55	-	-	-
Retained Earnings	2 717	2 801	2 909	3 052	3 079	3 076	3 002	2 891	2 785	2 730
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 782	27 958

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 5.50% (2016-2019), 3.00% thereafter
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 980	2 087	2 210	2 337	2 442	2 808	3 005	3 099	3 209
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 070)	(1 100)	(1 125)	(1 155)
Interest Paid	(511)	(514)	(542)	(588)	(775)	(912)	(1 200)	(1 318)	(1 294)	(1 301)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	609	623	679	598	549	570	615	694	768
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 790	1 400	1 390	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	21
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	2 013	1 268	730	572	243	279
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(167)	(243)	(240)	(242)	(261)	(358)	(246)	(251)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 514)	(1 827)	(1 301)	(1 144)	(975)	(979)
Net Increase (Decrease) in Cash	(270)	(55)	(64)	28	96	(10)	(1)	43	(38)	68
Cash at Beginning of Year	133	(137)	(192)	(256)	(228)	(132)	(141)	(143)	(100)	(138)
Cash at End of Year	(137)	(192)	(256)	(228)	(132)	(141)	(143)	(100)	(138)	(70)

ELECTRIC OPERATIONS (MH14)

ALTERNATE RATE SCENARIO - 6.00% (2016-2019), 3.00% thereafter

PROJECTED OPERATING STATEMENT

(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	87	180	283	391	451	511	574	642	713
BPIII Reserve Account	(30)	(33)	(35)	(38)	(12)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 957	2 069	2 199	2 363	2 482	2 849	3 047	3 142	3 254
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	509	545	574	737	863	1 160	1 283	1 284	1 292
Depreciation and Amortization	405	401	422	445	521	523	611	665	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	145	146	153	153	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 823	1 953	2 036	2 302	2 445	2 887	3 108	3 193	3 246
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	146	124	170	66	40	(28)	(60)	(52)	4
* Additional General Consumers Revenue										
Percent Increase	0.00%	6.00%	6.00%	6.00%	6.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Cumulative Percent Increase	0.00%	6.00%	12.36%	19.10%	26.25%	30.04%	33.94%	37.95%	42.09%	46.36%
Financial Ratios										
Equity	22%	18%	17%	16%	16%	15%	15%	14%	14%	14%
Interest Coverage	1.16	1.20	1.14	1.17	1.06	1.03	0.98	0.95	0.96	1.00
Capital Coverage	0.98	1.07	1.05	1.29	1.17	1.09	1.08	1.20	1.33	1.45

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 6.00% (2016-2019), 3.00% thereafter
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 293	2 594	2 726	2 167	2 229	2 432
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 583	27 665	28 298	27 727	27 780	27 955
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 777	21 306	21 992	22 155	22 450	22 441
Current and Other Liabilities	2 016	2 120	2 200	3 064	2 251	2 735	2 739	2 097	1 877	2 020
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	82	117	155	167	111	56	-	-	-
Retained Earnings	2 717	2 808	2 932	3 102	3 168	3 208	3 180	3 120	3 068	3 072
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 583	27 665	28 298	27 727	27 780	27 955

ELECTRIC OPERATIONS (MH14)
ALTERNATE RATE SCENARIO - 6.00% (2016-2019), 3.00% thereafter
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 987	2 102	2 235	2 372	2 479	2 846	3 044	3 139	3 251
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 070)	(1 101)	(1 126)	(1 155)
Interest Paid	(511)	(514)	(542)	(584)	(770)	(901)	(1 187)	(1 306)	(1 280)	(1 286)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	617	638	708	638	597	620	665	748	826
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 590	1 400	1 390	600	560	380
Sinking Fund Withdrawals	110	21	-	7	448	202	290	715	165	18
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	1 813	1 268	729	572	243	76
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(167)	(243)	(239)	(242)	(261)	(358)	(244)	(249)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 514)	(1 827)	(1 301)	(1 144)	(972)	(976)
Net Increase (Decrease) in Cash	(270)	(48)	(48)	56	(63)	38	48	93	19	(74)
Cash at Beginning of Year	133	(137)	(185)	(233)	(177)	(240)	(202)	(154)	(61)	(42)
Cash at End of Year	(137)	(185)	(233)	(177)	(240)	(202)	(154)	(61)	(42)	(116)

APPENDIX 3.6: SENSITIVITY ANALYSIS SCENARIOS

The Sensitivity Analysis included in IFF14 (Appendix 3.2, page 22) discusses the potential financial impacts of changes in key assumptions incorporated in IFF14. A change to one or more of the following assumptions could have a significant impact on projected financial results:

- Domestic load growth
- Interest rates
- Foreign exchange rates
- Export prices
- Capital expenditures
- Water flow conditions
- Rate Increases

Figure 3.6.1 below, reproduced from Appendix 3.2, shows the projected changes in electric operations retained earnings and incremental even annual rate increases/(decreases) required to achieve the same level of retained earnings in 2023/24 as forecast in IFF14.

Figure 3.6.1: Financial Impacts on Electric Operations of Sensitivity Analysis

	2016/17	2020/21	2023/24	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease)
Low Domestic Load Growth	(4)	(24)	(32)	0.04%
High Domestic Load Growth	(4)	54	65	-0.08%
+ 1% Interest	(45)	(416)	(1,057)	1.27%
- 1% Interest	43	392	975	-1.31%
C$/US$ Down 0.10 (C$ Strengthening)	5	(3)	(159)	0.20%
C$/US$ Up 0.10 (C$ Weakening)	(5)	3	159	-0.20%
Low Export Price	(44)	(304)	(704)	0.88%
High Export Price	28	245	626	-0.81%
5 Year Drought (starting in 2016/17)	N/A	(1,711)	N/A	2.43%
+ 1% Rate Increase in 2016	31	116	206	-0.26%
- 1% Rate Increase in 2016	(31)	(115)	(200)	0.26%
Capital Down $50 M MH	7	85	206	-0.26%
Capital Up $50 M MH	(7)	(85)	(205)	0.26%

Note: Appendix 3.2, Table 16-2 page 22 reflects consolidated results for the ±1%iInterest sensitivities, including gas operations.

The projected electric operations financial statements supporting each of the sensitivity analysis above are attached.

Low Domestic Load Growth:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 425	1 441	1 444	1 450	1 449	1 453	1 461	1 469
additional*	0	57	115	178	242	310	379	453	531	613
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	480	493	524	569	878	1 013	1 037	1 077
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 001	2 092	2 213	2 344	2 722	2 934	3 044	3 174
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	632
Finance Expense	495	510	548	582	752	888	1 195	1 327	1 335	1 351
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	189	199	203	200	227	256	249	257
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 953	2 041	2 313	2 467	2 916	3 145	3 233	3 296
Non-controlling Interest	25	12	8	7	6	4	11	1	(1)	(3)
Net Income	102	115	55	58	(94)	(119)	(184)	(210)	(190)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	10%	9%
Interest Coverage	1.16	1.16	1.06	1.06	0.92	0.90	0.86	0.84	0.86	0.91
Capital Coverage	0.98	1.02	0.93	1.08	0.87	0.80	0.81	0.93	1.08	1.22

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 598	2 728	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 788	27 966
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 101	3 081	2 231	2 674	2 629	2 133	2 060	2 134
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	149	160	106	53	-	-	-
Retained Earnings	2 717	2 778	2 833	2 892	2 797	2 678	2 494	2 284	2 093	1 969
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 788	27 966

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 031	2 124	2 221	2 341	2 719	2 931	3 041	3 172
Cash Paid to Suppliers and Employees	(803)	(871)	(940)	(970)	(995)	(1 009)	(1 063)	(1 092)	(1 116)	(1 146)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(928)	(1 223)	(1 350)	(1 331)	(1 343)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	566	591	477	438	464	518	609	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(263)	(358)	(252)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(981)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	79	(60)	(26)	78	95	(53)	(129)	(2)
Cash at Beginning of Year	133	(137)	(214)	(136)	(195)	(222)	(144)	(49)	(103)	(231)
Cash at End of Year	(137)	(214)	(136)	(195)	(222)	(144)	(49)	(103)	(231)	(234)

High Domestic Load Growth:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 496	1 524	1 537	1 553	1 562	1 574	1 591	1 607
additional*	0	57	120	188	258	332	409	490	578	670
BPIII Reserve Account	(30)	(32)	(35)	(37)	(11)	0	0	0	0	0
Extraprovincial	409	434	419	432	455	481	755	872	881	898
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 014	2 122	2 252	2 381	2 741	2 953	3 065	3 191
EXPENSES										
Operating and Administrative	486	542	552	558	572	586	601	607	619	631
Finance Expense	495	510	548	582	751	885	1 191	1 323	1 330	1 345
Depreciation and Amortization	405	401	422	445	521	524	612	666	736	752
Water Rentals and Assessments	124	123	111	112	113	115	124	127	132	132
Fuel and Power Purchased	134	130	202	214	218	215	240	271	267	278
Capital and Other Taxes	99	107	121	134	143	144	145	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 967	2 057	2 329	2 478	2 924	3 155	3 245	3 311
Non-controlling Interest	25	12	8	7	6	4	11	1	(1)	(3)
Net Income	102	115	56	73	(70)	(93)	(172)	(202)	(181)	(123)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.16	1.06	1.07	0.94	0.92	0.87	0.85	0.87	0.91
Capital Coverage	0.98	1.02	0.93	1.11	0.91	0.85	0.82	0.95	1.10	1.23

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 727	2 167	2 237	2 441
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 787	27 965
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 592	22 755	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 099	3 062	2 187	2 605	2 749	2 247	1 964	2 035
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	116	152	164	109	55	-	-	-
Retained Earnings	2 717	2 778	2 834	2 906	2 836	2 744	2 572	2 370	2 189	2 066
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 787	27 965

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 047	2 156	2 261	2 379	2 738	2 950	3 062	3 188
Cash Paid to Suppliers and Employees	(803)	(871)	(953)	(986)	(1 012)	(1 025)	(1 076)	(1 107)	(1 133)	(1 167)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(924)	(1 221)	(1 342)	(1 325)	(1 337)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	568	608	500	464	472	529	619	701
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 390	600	760	580
Sinking Fund Withdrawals	110	21	-	7	448	204	293	716	165	26
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	733	573	443	284
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 301)	(1 144)	(980)	(985)
Net Increase (Decrease) in Cash	(270)	(78)	81	(43)	(3)	104	(97)	(43)	82	(0)
Cash at Beginning of Year	133	(137)	(214)	(134)	(177)	(180)	(76)	(173)	(215)	(134)
Cash at End of Year	(137)	(214)	(134)	(177)	(180)	(76)	(173)	(215)	(134)	(134)

+1% Interest Rate:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	526	577	625	824	985	1 352	1 517	1 545	1 577
Depreciation and Amortization	405	401	423	446	522	526	615	670	740	756
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	269	257	267
Capital and Other Taxes	99	107	121	135	144	144	144	149	148	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 840	1 986	2 088	2 391	2 571	3 081	3 349	3 451	3 534
Non-controlling Interest	25	13	8	7	6	5	16	1	(1)	(3)
Net Income	102	100	30	20	(163)	(215)	(333)	(404)	(398)	(355)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	13%	12%	11%	8%	7%	5%
Interest Coverage	1.16	1.13	1.03	1.02	0.87	0.84	0.78	0.74	0.74	0.78
Capital Coverage	0.98	1.00	0.89	1.02	0.75	0.64	0.54	0.62	0.72	0.82

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 916	19 142	20 020	24 999	28 422	33 351	33 995	34 629	35 295
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 796)	(7 272)	(7 801)	(8 408)	(9 063)	(9 732)	(10 415)
Net Plant in Service	11 487	11 905	12 750	13 225	17 728	20 621	24 942	24 932	24 897	24 880
Construction in Progress	3 257	4 938	6 774	9 025	6 121	4 009	184	185	241	263
Current and Other Assets	1 798	1 570	1 824	2 282	2 303	2 633	2 771	2 231	2 306	2 514
Goodwill and Intangible Assets	198	186	176	167	169	182	174	158	143	128
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 876	21 837	25 051	26 717	27 865	28 505	27 938	28 003	28 183
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 889	21 377	22 306	23 192	23 555	24 250	24 441
Current and Other Liabilities	2 016	2 177	2 178	3 047	2 308	2 711	2 827	2 330	2 069	2 376
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 763	2 792	2 813	2 649	2 435	2 102	1 697	1 299	944
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 876	21 837	25 051	26 717	27 865	28 505	27 938	28 003	28 183

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 068)	(1 097)	(1 121)	(1 155)
Interest Paid	(511)	(526)	(577)	(635)	(863)	(1 024)	(1 385)	(1 533)	(1 539)	(1 570)
Interest Received	13	17	25	36	42	40	36	33	17	18
	558	578	544	562	409	350	312	344	408	473
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 390	2 800	1 790	1 600	790	960	580
Sinking Fund Withdrawals	110	21	-	8	448	206	296	718	167	33
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(31)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	3 047	2 022	1 661	945	765	644	291
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 528)	(3 158)	(3 285)	(2 301)	(1 599)	(1 026)	(758)	(700)	(699)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(243)	(248)	(267)	(359)	(260)	(269)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 751)	(3 347)	(3 549)	(2 565)	(1 882)	(1 323)	(1 147)	(990)	(998)
Net Increase (Decrease) in Cash	(270)	(97)	34	60	(133)	129	(66)	(37)	63	(234)
Cash at Beginning of Year	133	(137)	(234)	(200)	(140)	(274)	(145)	(211)	(248)	(185)
Cash at End of Year	(137)	(234)	(200)	(140)	(274)	(145)	(211)	(248)	(185)	(419)

-1% Interest Rate:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	497	518	541	683	792	1 049	1 148	1 141	1 148
Depreciation and Amortization	405	401	422	445	520	523	610	663	733	748
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	133
Fuel and Power Purchased	134	130	191	202	207	205	234	257	257	267
Capital and Other Taxes	99	107	120	134	143	144	145	152	153	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 810	1 926	2 002	2 247	2 374	2 773	2 964	3 046	3 099
Non-controlling Interest	25	12	7	6	5	3	5	0	(1)	(3)
Net Income	102	129	89	105	(20)	(20)	(37)	(20)	7	80
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	14%	14%	13%	13%	14%
Interest Coverage	1.16	1.19	1.11	1.11	0.98	0.98	0.97	0.98	1.01	1.07
Capital Coverage	0.98	1.03	0.98	1.16	1.00	0.99	1.07	1.26	1.44	1.58

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 907	19 112	19 955	24 914	28 244	33 057	33 699	34 329	34 991
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 794)	(7 268)	(7 795)	(8 397)	(9 046)	(9 709)	(10 387)
Net Plant in Service	11 487	11 896	12 720	13 161	17 646	20 450	24 660	24 653	24 620	24 604
Construction in Progress	3 257	4 926	6 736	8 939	5 961	3 871	156	185	241	263
Current and Other Assets	1 798	1 569	1 820	2 265	2 278	2 574	2 679	2 118	2 330	2 535
Goodwill and Intangible Assets	198	186	175	165	164	172	162	146	131	116
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 855	21 764	24 882	26 445	27 487	28 091	27 534	27 737	27 916
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 192	22 155	22 650	22 641
Current and Other Liabilities	2 016	2 127	2 217	3 105	2 119	2 622	2 604	2 134	1 806	1 876
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 792	2 881	2 986	2 966	2 946	2 909	2 889	2 896	2 976
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 855	21 764	24 882	26 445	27 487	28 091	27 534	27 737	27 916

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(999)	(1 015)	(1 069)	(1 100)	(1 126)	(1 156)
Interest Paid	(511)	(505)	(517)	(552)	(712)	(822)	(1 077)	(1 166)	(1 129)	(1 138)
Interest Received	13	13	17	25	29	29	26	24	13	14
	558	594	597	635	548	541	608	699	810	899
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 800	1 390	1 400	390	770	380
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	21
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(100)	(24)	(41)	(32)
	1 218	2 077	2 636	2 857	2 023	1 259	740	362	453	79
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 508)	(3 111)	(3 203)	(2 207)	(1 503)	(994)	(755)	(696)	(695)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(242)	(261)	(357)	(245)	(249)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 731)	(3 299)	(3 467)	(2 468)	(1 781)	(1 285)	(1 142)	(971)	(974)
Net Increase (Decrease) in Cash	(270)	(60)	(66)	24	103	19	64	(81)	292	4
Cash at Beginning of Year	133	(137)	(197)	(263)	(239)	(135)	(116)	(52)	(133)	158
Cash at End of Year	(137)	(197)	(263)	(239)	(135)	(116)	(52)	(133)	158	162

C$/US$ Down 0.10 (C$ Strengthening):

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	398	413	420	440	472	747	862	875	901
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 891	1 972	2 064	2 184	2 309	2 662	2 862	2 970	3 096
EXPENSES										
Operating and Administrative	486	538	548	553	567	582	597	603	615	628
Finance Expense	495	481	521	548	723	859	1 164	1 295	1 320	1 355
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	122	112	112	111	113	124	126	131	132
Fuel and Power Purchased	134	126	182	192	197	195	221	249	243	252
Capital and Other Taxes	99	107	121	134	143	144	144	150	149	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 787	1 916	1 997	2 274	2 428	2 874	3 101	3 206	3 290
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	117	63	74	(85)	(115)	(202)	(238)	(237)	(197)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	19%	17%	16%	15%	14%	12%	10%	10%	9%
Interest Coverage	1.16	1.17	1.08	1.08	0.92	0.90	0.84	0.82	0.82	0.86
Capital Coverage	0.98	0.99	0.92	1.08	0.86	0.77	0.74	0.83	0.97	1.10

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 544	1 794	2 209	2 272	2 575	2 710	2 185	2 254	2 443
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 840	21 773	24 902	26 562	27 645	28 282	27 745	27 804	27 967
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 643	16 516	18 565	21 068	21 822	22 774	22 953	23 448	23 640
Current and Other Liabilities	2 016	2 150	2 102	3 014	2 192	2 626	2 563	2 143	1 930	2 061
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 779	2 842	2 917	2 831	2 716	2 515	2 277	2 040	1 842
Accumulated Other Comprehensive Income	94	(259)	(283)	(258)	(240)	(210)	(242)	(281)	(303)	(304)
	16 993	18 840	21 773	24 902	26 562	27 645	28 282	27 745	27 804	27 967

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 921	2 003	2 097	2 192	2 307	2 659	2 860	2 968	3 093
Cash Paid to Suppliers and Employees	(803)	(863)	(929)	(959)	(985)	(1 000)	(1 052)	(1 080)	(1 104)	(1 136)
Interest Paid	(511)	(502)	(533)	(579)	(771)	(918)	(1 213)	(1 345)	(1 331)	(1 347)
Interest Received	13	15	20	29	33	33	29	28	15	16
	558	571	561	589	469	422	423	463	548	626
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	760	580
Sinking Fund Withdrawals	110	21	-	18	408	202	286	653	168	43
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 155)	(300)	(825)	(653)	(426)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 868	2 013	1 483	950	575	461	301
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(185)	(165)	(222)	(237)	(243)	(260)	(331)	(253)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 725)	(3 320)	(3 488)	(2 512)	(1 828)	(1 300)	(1 117)	(981)	(987)
Net Increase (Decrease) in Cash	(270)	(76)	77	(31)	(30)	76	73	(79)	27	(60)
Cash at Beginning of Year	133	(137)	(213)	(136)	(167)	(197)	(121)	(47)	(126)	(99)
Cash at End of Year	(137)	(213)	(136)	(167)	(197)	(121)	(47)	(126)	(99)	(160)

C$/US$ Up 0.10 (C$ Weakening):

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	470	486	494	517	556	887	1 025	1 042	1 074
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 964	2 044	2 138	2 261	2 394	2 802	3 025	3 138	3 269
EXPENSES										
Operating and Administrative	486	545	555	561	575	589	604	611	623	635
Finance Expense	495	539	574	615	780	915	1 223	1 356	1 347	1 343
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	113	113	113	114	125	128	132	133
Fuel and Power Purchased	134	135	200	212	217	215	246	277	272	282
Capital and Other Taxes	99	107	120	134	143	144	145	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 862	1 996	2 091	2 360	2 514	2 967	3 199	3 273	3 317
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	114	56	54	(94)	(117)	(155)	(174)	(136)	(51)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	17%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.15	1.06	1.05	0.92	0.91	0.88	0.87	0.90	0.96
Capital Coverage	0.98	1.04	0.95	1.11	0.90	0.84	0.90	1.05	1.21	1.35

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 595	1 853	2 327	2 319	2 621	2 764	2 167	2 222	2 440
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 891	21 832	25 020	26 609	27 692	28 335	27 727	27 772	27 964
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 973	16 846	18 813	21 286	21 989	22 810	22 958	23 252	23 242
Current and Other Liabilities	2 016	2 152	2 094	3 124	2 235	2 682	2 664	2 084	1 926	2 141
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 777	2 833	2 886	2 793	2 676	2 521	2 348	2 211	2 160
Accumulated Other Comprehensive Income	94	(538)	(535)	(468)	(416)	(346)	(332)	(316)	(307)	(306)
	16 993	18 891	21 832	25 020	26 609	27 692	28 335	27 727	27 772	27 964

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 994	2 075	2 171	2 269	2 391	2 799	3 022	3 135	3 266
Cash Paid to Suppliers and Employees	(803)	(880)	(956)	(987)	(1 014)	(1 029)	(1 086)	(1 118)	(1 143)	(1 175)
Interest Paid	(511)	(526)	(561)	(608)	(798)	(938)	(1 231)	(1 354)	(1 328)	(1 335)
Interest Received	13	15	22	32	37	36	32	30	15	16
	558	603	581	608	494	460	514	580	679	772
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	380
Sinking Fund Withdrawals	110	21	-	-	488	206	302	780	180	11
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 235)	(330)	(875)	(783)	(456)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 850	2 013	1 457	916	572	243	69
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(219)	(173)	(263)	(245)	(247)	(284)	(385)	(252)	(257)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 759)	(3 329)	(3 529)	(2 520)	(1 832)	(1 323)	(1 172)	(980)	(984)
Net Increase (Decrease) in Cash	(270)	(79)	88	(71)	(13)	85	107	(19)	(59)	(143)
Cash at Beginning of Year	133	(137)	(216)	(128)	(198)	(211)	(127)	(20)	(39)	(98)
Cash at End of Year	(137)	(216)	(128)	(198)	(211)	(127)	(20)	(39)	(98)	(241)

Low Export Price:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	393	404	422	440	693	808	823	841
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	1 951	2 048	2 166	2 277	2 609	2 808	2 918	3 036
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	549	586	758	896	1 208	1 346	1 353	1 375
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	113	112	114	124	127	131	131
Fuel and Power Purchased	134	130	177	188	190	186	214	244	232	238
Capital and Other Taxes	99	107	121	134	143	144	144	149	149	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 944	2 034	2 306	2 461	2 914	3 151	3 231	3 299
Non-controlling Interest	25	12	8	8	6	5	18	2	0	(1)
Net Income	102	115	15	22	(134)	(179)	(288)	(340)	(312)	(264)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	12%	11%	9%	8%	7%
Interest Coverage	1.16	1.16	1.02	1.02	0.88	0.86	0.78	0.75	0.77	0.81
Capital Coverage	0.98	1.02	0.87	1.02	0.81	0.69	0.62	0.70	0.87	0.98

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 729	2 168	2 243	2 449
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 670	28 301	27 728	27 793	27 973
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 377	22 106	22 992	23 155	23 650	24 241
Current and Other Liabilities	2 016	2 151	2 141	3 156	2 146	2 650	2 710	2 344	2 197	2 013
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 793	2 815	2 680	2 502	2 214	1 873	1 561	1 297
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 670	28 301	27 728	27 793	27 973

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	1 982	2 081	2 174	2 274	2 606	2 806	2 916	3 033
Cash Paid to Suppliers and Employees	(803)	(871)	(929)	(959)	(983)	(995)	(1 049)	(1 073)	(1 095)	(1 125)
Interest Paid	(511)	(514)	(546)	(592)	(786)	(934)	(1 234)	(1 370)	(1 345)	(1 365)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	528	560	441	380	354	391	490	560
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 990	1 600	1 590	600	760	980
Sinking Fund Withdrawals	110	21	-	7	448	205	295	718	165	30
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 213	1 471	934	575	443	688
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(247)	(264)	(359)	(256)	(264)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 517)	(1 831)	(1 304)	(1 145)	(985)	(991)
Net Increase (Decrease) in Cash	(270)	(78)	41	(91)	137	19	(15)	(179)	(52)	256
Cash at Beginning of Year	133	(137)	(214)	(173)	(264)	(127)	(108)	(123)	(302)	(354)
Cash at End of Year	(137)	(214)	(173)	(264)	(127)	(108)	(123)	(302)	(354)	(98)

High Export Price:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	487	499	536	563	938	1 064	1 101	1 123
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 045	2 143	2 280	2 400	2 853	3 065	3 197	3 318
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	546	579	746	879	1 184	1 309	1 311	1 320
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	134	135
Fuel and Power Purchased	134	130	201	215	224	218	256	279	287	294
Capital and Other Taxes	99	107	121	134	143	144	145	152	152	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 965	2 054	2 328	2 476	2 934	3 151	3 250	3 305
Non-controlling Interest	25	12	7	6	5	2	(0)	(1)	(3)	(5)
Net Income	102	115	88	95	(44)	(73)	(81)	(87)	(56)	7
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	15%	14%	13%	12%	12%	12%
Interest Coverage	1.16	1.16	1.10	1.09	0.96	0.94	0.94	0.93	0.96	1.01
Capital Coverage	0.98	1.02	0.99	1.15	0.96	0.88	1.01	1.14	1.33	1.46

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 332	33 202	33 845	34 477	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 799	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 597	2 760	2 166	2 341	2 477
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 667	28 330	27 726	27 890	28 000
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 706	22 592	22 555	23 050	23 041
Current and Other Liabilities	2 016	2 151	2 068	3 009	2 108	2 705	2 591	2 140	1 836	1 910
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 866	2 961	2 917	2 844	2 763	2 676	2 620	2 627
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 667	28 330	27 726	27 890	28 000

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 077	2 176	2 288	2 398	2 850	3 062	3 194	3 315
Cash Paid to Suppliers and Employees	(803)	(871)	(952)	(986)	(1 016)	(1 027)	(1 092)	(1 124)	(1 157)	(1 186)
Interest Paid	(511)	(514)	(543)	(592)	(780)	(923)	(1 213)	(1 332)	(1 306)	(1 312)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	603	628	527	482	576	634	746	833
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 400	1 590	400	760	380
Sinking Fund Withdrawals	110	21	-	7	448	204	293	715	165	24
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 269	932	372	443	82
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 009)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(244)	(261)	(358)	(248)	(253)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 515)	(1 829)	(1 300)	(1 144)	(977)	(981)
Net Increase (Decrease) in Cash	(270)	(78)	116	(23)	25	(78)	207	(138)	212	(66)
Cash at Beginning of Year	133	(137)	(214)	(99)	(121)	(96)	(174)	33	(104)	108
Cash at End of Year	(137)	(214)	(99)	(121)	(96)	(174)	33	(104)	108	42

5 Year Drought (starting in 2016/17):

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	275	286	305	353	687	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	1 833	1 930	2 048	2 190	2 602	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	562	599	568	584	599	607	619	631
Finance Expense	495	510	552	609	806	958	1 283	1 427	1 441	1 462
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	84	78	93	93	107	127	132	132
Fuel and Power Purchased	134	130	367	525	261	316	302	263	257	267
Capital and Other Taxes	99	107	121	134	143	143	142	148	147	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	2 119	2 400	2 403	2 629	3 056	3 249	3 343	3 417
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	(279)	(464)	(349)	(435)	(444)	(304)	(290)	(238)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	15%	11%	10%	8%	6%	4%	2%	2%
Interest Coverage	1.16	1.16	0.68	0.56	0.71	0.66	0.68	0.79	0.80	0.84
Capital Coverage	0.98	1.02	0.39	0.14	0.41	0.22	0.36	0.77	0.91	1.03

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 304	2 610	2 742	2 180	2 256	2 462
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 594	27 680	28 314	27 740	27 806	27 985
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 881	19 489	22 377	23 306	24 392	24 755	25 250	25 441
Current and Other Liabilities	2 016	2 151	2 234	3 135	2 148	2 710	2 730	2 126	1 959	2 147
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 499	2 036	1 687	1 251	807	503	213	(24)
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 594	27 680	28 314	27 740	27 806	27 985

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	1 864	1 963	2 057	2 187	2 600	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(1 100)	(1 302)	(1 031)	(1 102)	(1 116)	(1 096)	(1 120)	(1 155)
Interest Paid	(511)	(514)	(547)	(614)	(835)	(998)	(1 310)	(1 449)	(1 437)	(1 454)
Interest Received	13	15	21	30	35	35	31	29	15	16
	558	587	237	77	225	122	205	426	510	586
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 390	3 800	3 190	1 800	1 790	800	760	580
Sinking Fund Withdrawals	110	21	-	7	448	213	305	718	178	45
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	3 036	3 457	2 413	1 678	1 144	775	455	303
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(250)	(257)	(277)	(358)	(271)	(278)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 524)	(1 842)	(1 317)	(1 144)	(999)	(1 005)
Net Increase (Decrease) in Cash	(270)	(78)	(50)	25	114	(41)	33	57	(34)	(116)
Cash at Beginning of Year	133	(137)	(214)	(264)	(239)	(125)	(166)	(133)	(77)	(111)
Cash at End of Year	(137)	(214)	(264)	(239)	(125)	(166)	(133)	(77)	(111)	(227)

+1% Rate Increase in 2015/16:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	72	133	199	267	338	412	491	574	662
BPIII Reserve Account	(30)	(33)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 942	2 023	2 117	2 239	2 369	2 750	2 963	3 074	3 203
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	546	579	748	882	1 188	1 317	1 324	1 338
Depreciation and Amortization	405	401	422	445	521	524	612	666	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 955	2 042	2 314	2 466	2 914	3 141	3 230	3 292
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	130	76	82	(70)	(93)	(154)	(178)	(157)	(92)
* Additional General Consumers Revenue										
Percent Increase	0.00%	4.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	4.95%	9.10%	13.40%	17.88%	22.54%	27.38%	32.41%	37.64%	43.08%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	14%	13%	11%	11%	10%
Interest Coverage	1.16	1.18	1.09	1.08	0.94	0.92	0.88	0.87	0.88	0.93
Capital Coverage	0.98	1.04	0.97	1.12	0.91	0.85	0.87	0.99	1.14	1.28

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 597	2 727	2 167	2 236	2 440
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 585	27 668	28 298	27 727	27 786	27 963
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 706	22 592	22 755	23 050	23 241
Current and Other Liabilities	2 016	2 136	2 065	3 019	2 144	2 761	2 687	2 161	2 053	2 093
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	116	152	163	109	54	-	-	-
Retained Earnings	2 717	2 793	2 868	2 950	2 881	2 788	2 634	2 456	2 299	2 207
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 585	27 668	28 298	27 727	27 786	27 963

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 972	2 054	2 150	2 248	2 366	2 747	2 960	3 071	3 201
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(543)	(593)	(784)	(923)	(1 210)	(1 340)	(1 319)	(1 329)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	601	590	615	499	463	499	549	643	732
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 400	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	293	715	165	25
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 269	932	572	243	283
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(261)	(358)	(251)	(256)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 515)	(1 830)	(1 301)	(1 144)	(979)	(984)
Net Increase (Decrease) in Cash	(270)	(63)	104	(36)	(3)	(97)	130	(23)	(93)	31
Cash at Beginning of Year	133	(137)	(200)	(96)	(133)	(136)	(233)	(103)	(127)	(220)
Cash at End of Year	(137)	(200)	(96)	(133)	(136)	(233)	(103)	(127)	(220)	(189)

-1% Rate Increase in 2015/16:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	43	102	167	233	303	376	452	534	620
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 913	1 993	2 085	2 206	2 334	2 713	2 925	3 034	3 161
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	549	584	755	891	1 200	1 333	1 342	1 359
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	150	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 957	2 046	2 320	2 475	2 927	3 157	3 248	3 313
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	101	43	46	(109)	(138)	(203)	(232)	(215)	(155)
* Additional General Consumers Revenue										
Percent Increase	0.00%	2.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	2.95%	7.02%	11.24%	15.64%	20.21%	24.95%	29.89%	35.02%	40.35%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	9%	9%
Interest Coverage	1.16	1.14	1.05	1.05	0.90	0.89	0.85	0.83	0.84	0.89
Capital Coverage	0.98	0.99	0.91	1.06	0.85	0.77	0.79	0.90	1.04	1.17

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 728	2 167	2 239	2 443
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 669	28 300	27 727	27 789	27 967
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 450	23 641
Current and Other Liabilities	2 016	2 166	2 128	3 119	2 284	2 746	2 720	2 246	1 999	2 103
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	150	161	107	54	-	-	-
Retained Earnings	2 717	2 763	2 807	2 853	2 743	2 606	2 403	2 171	1 956	1 801
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 669	28 300	27 727	27 789	27 967

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 943	2 024	2 118	2 214	2 331	2 711	2 922	3 031	3 159
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 098)	(1 123)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(930)	(1 222)	(1 354)	(1 336)	(1 351)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	573	556	583	464	422	451	498	588	669
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	760	580
Sinking Fund Withdrawals	110	21	-	8	448	205	294	717	165	28
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	934	574	443	286
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(246)	(263)	(358)	(253)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 831)	(1 303)	(1 144)	(982)	(987)
Net Increase (Decrease) in Cash	(270)	(92)	69	(68)	(39)	61	81	(73)	49	(33)
Cash at Beginning of Year	133	(137)	(229)	(160)	(228)	(267)	(206)	(125)	(197)	(149)
Cash at End of Year	(137)	(229)	(160)	(228)	(267)	(206)	(125)	(197)	(149)	(181)

Capital Down $50 million /year:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	545	575	742	874	1 177	1 304	1 308	1 319
Depreciation and Amortization	405	400	420	441	515	516	603	655	723	737
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	120	134	142	143	144	150	150	159
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 823	1 950	2 033	2 301	2 449	2 893	3 116	3 200	3 256
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	117	65	75	(73)	(94)	(151)	(172)	(147)	(77)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	14%	13%	11%	11%	11%
Interest Coverage	1.16	1.16	1.08	1.07	0.94	0.92	0.88	0.87	0.89	0.94
Capital Coverage	0.98	1.11	1.03	1.22	0.99	0.92	0.94	1.08	1.25	1.40

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 862	19 027	19 838	24 757	28 083	32 902	33 496	34 078	34 692
Accumulated Depreciation	(5 676)	(6 011)	(6 389)	(6 788)	(7 257)	(7 777)	(8 372)	(9 012)	(9 664)	(10 329)
Net Plant in Service	11 487	11 851	12 638	13 050	17 500	20 306	24 531	24 484	24 414	24 363
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 596	2 726	2 167	2 233	2 436
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 816	21 703	24 818	26 397	27 437	28 029	27 420	27 440	27 582
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 392	22 555	22 850	22 841
Current and Other Liabilities	2 016	2 100	2 191	3 108	2 191	2 766	2 649	2 078	1 921	2 112
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 780	2 845	2 920	2 847	2 753	2 603	2 431	2 284	2 207
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 816	21 703	24 818	26 397	27 437	28 029	27 420	27 440	27 582

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(972)	(999)	(1 014)	(1 068)	(1 098)	(1 123)	(1 154)
Interest Paid	(511)	(515)	(543)	(584)	(774)	(912)	(1 199)	(1 327)	(1 304)	(1 311)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	586	576	608	493	457	493	544	639	731
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 790	1 400	1 590	600	560	380
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	22
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	2 013	1 268	931	572	243	80
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 468)	(3 084)	(3 194)	(2 203)	(1 500)	(960)	(706)	(648)	(647)
Sinking Fund Payment	(125)	(202)	(167)	(243)	(239)	(243)	(261)	(358)	(248)	(253)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 692)	(3 273)	(3 458)	(2 464)	(1 778)	(1 251)	(1 094)	(926)	(930)
Net Increase (Decrease) in Cash	(270)	(28)	(61)	6	41	(52)	172	21	(44)	(119)
Cash at Beginning of Year	133	(137)	(165)	(226)	(219)	(178)	(230)	(58)	(37)	(81)
Cash at End of Year	(137)	(165)	(226)	(219)	(178)	(230)	(58)	(37)	(81)	(200)

Capital Up $50 million /year:

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	551	588	761	900	1 211	1 347	1 359	1 379
Depreciation and Amortization	405	401	425	449	527	532	623	678	750	768
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	135	144	145	145	151	151	162
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 962	2 055	2 334	2 493	2 949	3 184	3 279	3 351
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	53	53	(106)	(138)	(206)	(239)	(226)	(172)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	9%	9%
Interest Coverage	1.16	1.16	1.06	1.05	0.91	0.89	0.84	0.82	0.84	0.88
Capital Coverage	0.98	0.94	0.87	0.99	0.79	0.72	0.73	0.83	0.96	1.07

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS										
Plant in Service	17 163	17 962	19 227	20 138	25 157	28 583	33 502	34 196	34 878	35 592
Accumulated Depreciation	(5 676)	(6 012)	(6 395)	(6 802)	(7 283)	(7 819)	(8 434)	(9 098)	(9 777)	(10 473)
Net Plant in Service	11 487	11 950	12 832	13 336	17 874	20 764	25 069	25 098	25 101	25 119
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 823	2 268	2 297	2 600	2 730	2 168	2 242	2 447
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 915	21 898	25 104	26 774	27 900	28 571	28 035	28 135	28 348
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 889	21 377	22 106	22 992	23 355	23 850	24 041
Current and Other Liabilities	2 016	2 201	2 201	3 030	2 237	2 742	2 761	2 131	1 933	2 089
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 777	2 831	2 883	2 777	2 639	2 433	2 193	1 967	1 796
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 915	21 898	25 104	26 774	27 900	28 571	28 035	28 135	28 348

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(943)	(974)	(1 001)	(1 016)	(1 070)	(1 099)	(1 124)	(1 157)
Interest Paid	(511)	(514)	(546)	(598)	(794)	(940)	(1 238)	(1 366)	(1 354)	(1 371)
Interest Received	13	15	21	30	35	35	31	28	15	16
	558	587	571	593	471	428	452	504	588	668
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 400	2 790	1 600	1 590	800	760	580
Sinking Fund Withdrawals	110	21	-	8	448	206	296	718	166	31
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	3 058	2 013	1 471	935	775	443	289
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 568)	(3 184)	(3 294)	(2 303)	(1 600)	(1 060)	(806)	(748)	(747)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(243)	(248)	(265)	(358)	(256)	(263)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 792)	(3 374)	(3 558)	(2 567)	(1 882)	(1 355)	(1 194)	(1 034)	(1 041)
Net Increase (Decrease) in Cash	(270)	(127)	34	92	(84)	17	33	85	(3)	(85)
Cash at Beginning of Year	133	(137)	(264)	(231)	(138)	(222)	(205)	(172)	(88)	(91)
Cash at End of Year	(137)	(264)	(231)	(138)	(222)	(205)	(172)	(88)	(91)	(175)

MANITOBA HYDRO
DEBT MANAGEMENT STRATEGY

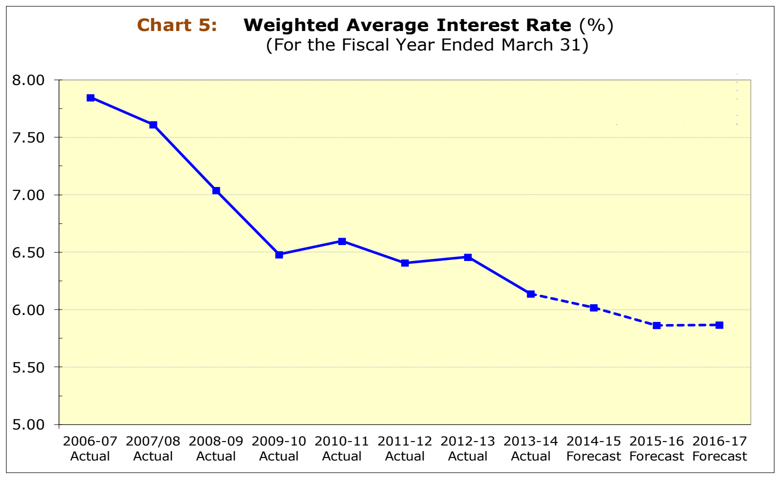
2014/15, 2015/16 AND 2016/17

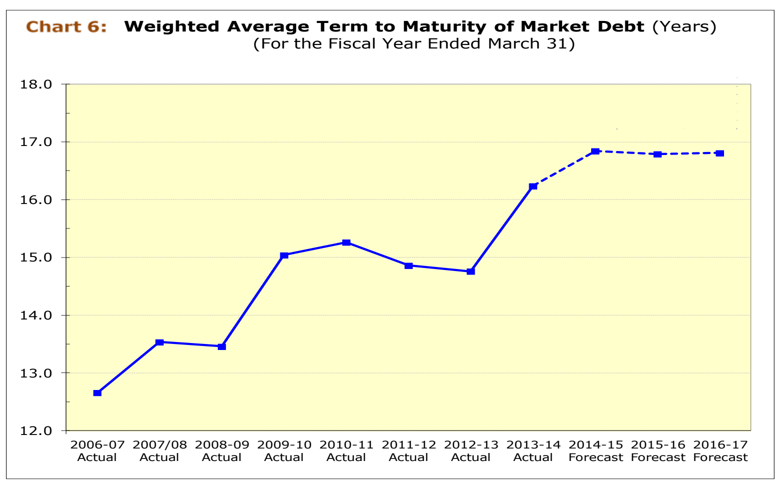
Manitoba Hydro's fundamental debt management objective is to provide **stable, low cost funding** to meet the financial obligations and liquidity needs of the Corporation.

The low interest rate environment over the past few years has provided the opportunity for Manitoba Hydro to secure stable, low cost funding.

Since 2006/07, the debt portfolio's net weighted average interest rate has decreased by nearly 2.0%. To enhance the debt portfolio stability, the weighted average term to maturity of its market debt portfolio has increased by over three years.

In order to mitigate refinancing risk, to maintain financing flexibility during the upcoming decade, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term fixed rate financings with maturities of 10 years and longer.





Manitoba Hydro

Treasury Division
December 2014

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1.0 Purpose of this Document

The *Debt Management Strategy* document provides information on the historical growth of the Corporation's investment in fixed assets and the corresponding increase in Manitoba Hydro's long term debt. The document also summarizes the statutes that govern the Corporation's financing programs, and outlines the debt management strategies that will address the Corporation's financing requirements for the 2014/15, 2015/16 and 2016/17 fiscal years.

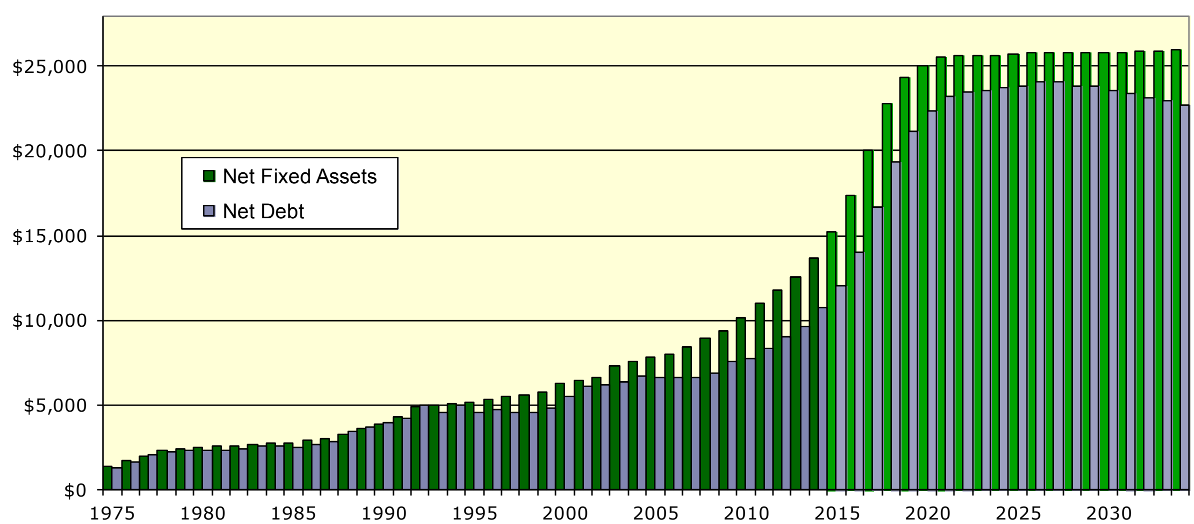
2.0 Overview of Manitoba Hydro's Capital Financing Program

As with most energy utilities, debt is an essential component of Manitoba Hydro's corporate capital structure. As a Crown Corporation owned by the Province of Manitoba, Manitoba Hydro does not have access to share capital as a source of funds. Therefore, in order to adequately provide for the long term energy requirements of the province, Manitoba Hydro must rely on debt as its primary source of external financing.

Debt financing has been beneficial for Manitoba Hydro and its ratepayers. It has fueled the growth of the Corporation from the early days of farm electrification and the development of the Winnipeg River generation system, through the years of development of the Nelson River generation and transmission system, right up to the recent construction of the Wuskwatim Generating station in northern Manitoba. None of this would have been possible without debt financing.

Chart 1 illustrates the growth in net fixed assets and net long term debt since 1975. While net debt has grown to approximately $10.8 billion as at March 31, 2014, the corresponding investment in generation, transmission, distribution and other assets has grown at a much greater pace to a net book value of approximately $13.6 billion at March 31, 2014. Moving forward, both the level of net fixed assets and net debt are forecasted to grow until the 2020s before the projected level of net debt begins to decline after 2025.

Chart 1: **Manitoba Hydro**
Net Fixed Assets & Net Debt
(Actuals to March 31, 2014 in millions of dollars at fiscal year ending)



The *Capital Expenditure Forecast* (CEF14) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba, as well as expenditures required to meet firm sale commitments outside the province. The CEF14 totals $17.8 billion for the ten year period from 2014/15 to 2023/24. Expenditures for Major New Generation & Transmission total $11.7 billion, with the balance of $6.1 billion comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

While debt financing provides the majority of funding necessary for investment in long term assets, Manitoba Hydro also funds a significant portion of its capital requirements from cash generated from operations. Utilizing funds from operations reduces the amount that would otherwise need to be borrowed each year by the Corporation. The net cash flow from operations for the next 10 years is forecast to be nearly $6.2 billion, with an average during this timeframe of nearly $620 million per fiscal year.

3.0 Borrowing Authority of Manitoba Hydro

Manitoba Hydro's authority to issue debt is provided through The Manitoba Hydro Act, The Loan Act, and The Financial Administration Act. The following sections provide a synopsis of the authority received by Manitoba Hydro through this legislation.

3.1 The Manitoba Hydro Act

The Manitoba Hydro Act grants the following powers to the Corporation for issuing debt in the name of the Manitoba Hydro-Electric Board:

1. **Temporary Borrowing Authority**
   The principal amount of short term promissory notes outstanding at any one time shall not exceed in the aggregate the sum of $500 million of principal outstanding at any one time, upon such terms, for such periods, and upon such other conditions, as the Corporation may determine.

2. **Government Guarantee**
   The Government may, on such terms as may be approved by the Lieutenant Governor in Council, guarantee the payment of the principal and interest on any borrowings of the Corporation under this section.

3. **Power of the Corporation to Borrow and Issue Securities**
   The Corporation may raise money by way of loan, notes, bonds, debentures or other securities in the name of The Manitoba Hydro-Electric Board subject to the approval of the Lieutenant Governor in Council for purposes provided in the Manitoba Hydro Act or to refund any loan or advance previously made by the Corporation.

   Borrowing authority, under Section 35 of the Manitoba Hydro Act, will treat Canadian and US borrowings on a one for one par value basis. The borrowing authority will be abated for the Canadian dollar equivalent using the nominal rate of exchange when the loan is denominated in a currency other than Canadian or US dollars.

3.2 The Loan Act

The Loan Act is approved each year and grants Manitoba Hydro borrowing authority to meet the Corporation's projected financing requirements. Authority granted under the Loan Act is for purposes other than to refinance debt, including new investment requirements. Refunding authority to refinance maturing long term debt is provided through the Financial Administration Act.

3.3 The Financial Administration Act

The Financial Administration Act authorizes the Minister of Finance to borrow money for any purpose authorized by any Act of the Legislature or for the payment, refunding, refinancing or renewal, from time to time, of the whole or any part of any loan made or provincial securities issued under any Act.

4.0 Debt Management Objectives

Manitoba Hydro's fundamental *debt management objective is to provide stable, low cost funding to meet the financial obligations and liquidity needs of the Corporation*. Manitoba Hydro continually monitors the interest rate environment and acts to secure stable, low cost financing with terms to maturity that fit the Corporation's debt maturity schedule and meet investor appetite.

Manitoba Hydro's debt is viewed to be self-supporting by credit rating agencies (Dominion Bond Rating Service, Moody's Investors Service, and Standard & Poor's). In order to maintain the self-supporting nature of the Corporation's debt obligations and the attractive financing rates associated with the Corporation's debt, Manitoba Hydro places significant emphasis on the following financial targets:

Debt/Equity – Maintain a minimum debt/equity ratio of 75:25. The debt to equity ratio indicates the relative percentage of assets financed through debt versus equity. It is calculated by dividing debt by debt plus equity.

Interest Coverage – Maintain an annual gross interest coverage ratio greater than 1.20. The interest coverage ratio indicates the extent to which net income is sufficient to pay gross interest on debt. It is calculated by dividing net income plus gross interest on debt by gross interest on debt.

Capital Coverage – Maintain a capital coverage ratio of greater than 1.20. The capital coverage ratio indicates the extent to which cash generated internally is sufficient to fund capital construction expenditures without additional external financing. It is calculated by dividing cash generated from operations by capital construction expenditures (excluding major new generation & transmission projects).

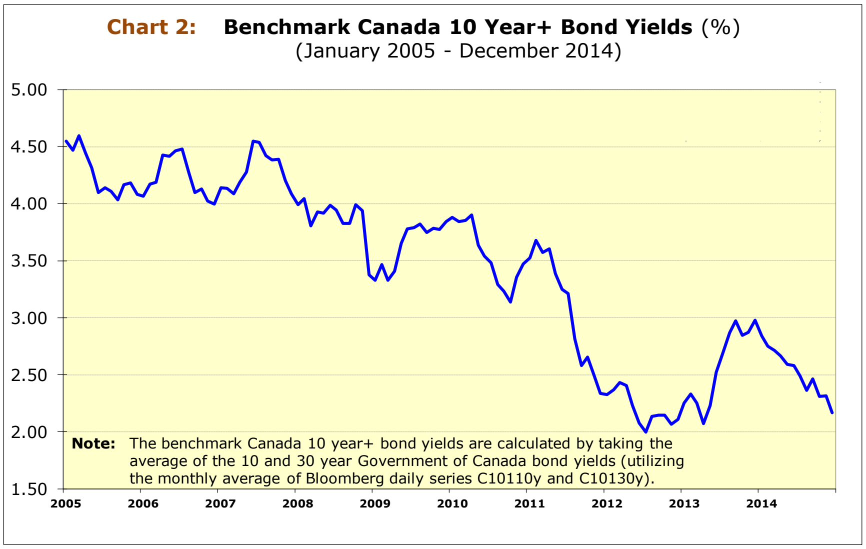
Note: Financial targets may not be achieved during years of major investment in the generation and transmission system.

5.0 Analysis and Commentary

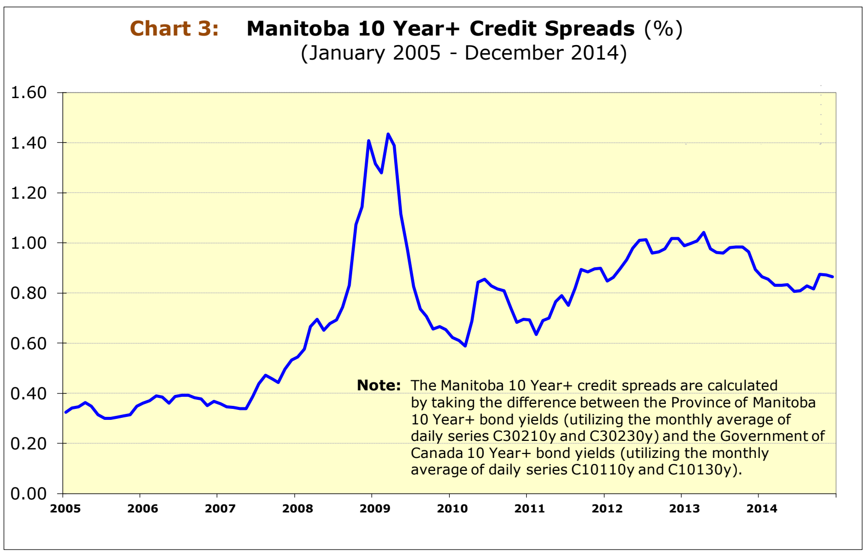
> "Unexpectedly slow global recovery has meant that monetary conditions in advanced economies, including Canada, have been very stimulative for much longer than envisioned in the aftermath of the financial crisis."
>
> Bank of Canada, *Financial System Review*, December 2014, page 5.

While short term interest rates remain artificially anchored at their extraordinary low levels by central bank monetary policy interventions, long term interest rates began to rise in May 2013 as the financial markets anticipated the potential tapering of the U.S. Federal Reserve's quantitative easing program in the latter part of 2013. Since early 2014, yields in the long end have once again trended downward with the uncertainty regarding the pace of the U.S. economic recovery, the re-emergence of geopolitical issues, global growth concerns and falling oil prices.

The long term interest rates in the Canadian capital markets showed a similar trajectory. As shown on historical interest rate chart for the **Benchmark Canada 10 Year+ bond yields** (Chart 1), while the interest rates in the 12 month period prior to May 2013 were generally range bound at historically low levels, by September 2013 interest rates rose nearly 1%. Since then, long term interest rates have drifted downward, once again approaching historically low levels.



The **credit spreads** between the benchmark long term Government of Canada bonds and the all-in cost to the Province of Manitoba have tightened since May 2013 (Chart 3). The net impact of these movements is that Manitoba Hydro's current interest rate environment continues to be low in comparison to historical rates across the entire spectrum of the yield curve. This situation is demonstrated on the interest rate chart on page 7 that depicts historical interest rates dating back to January 1948, as well as a range of externally forecasted interest rates to 2034 (Chart 4).



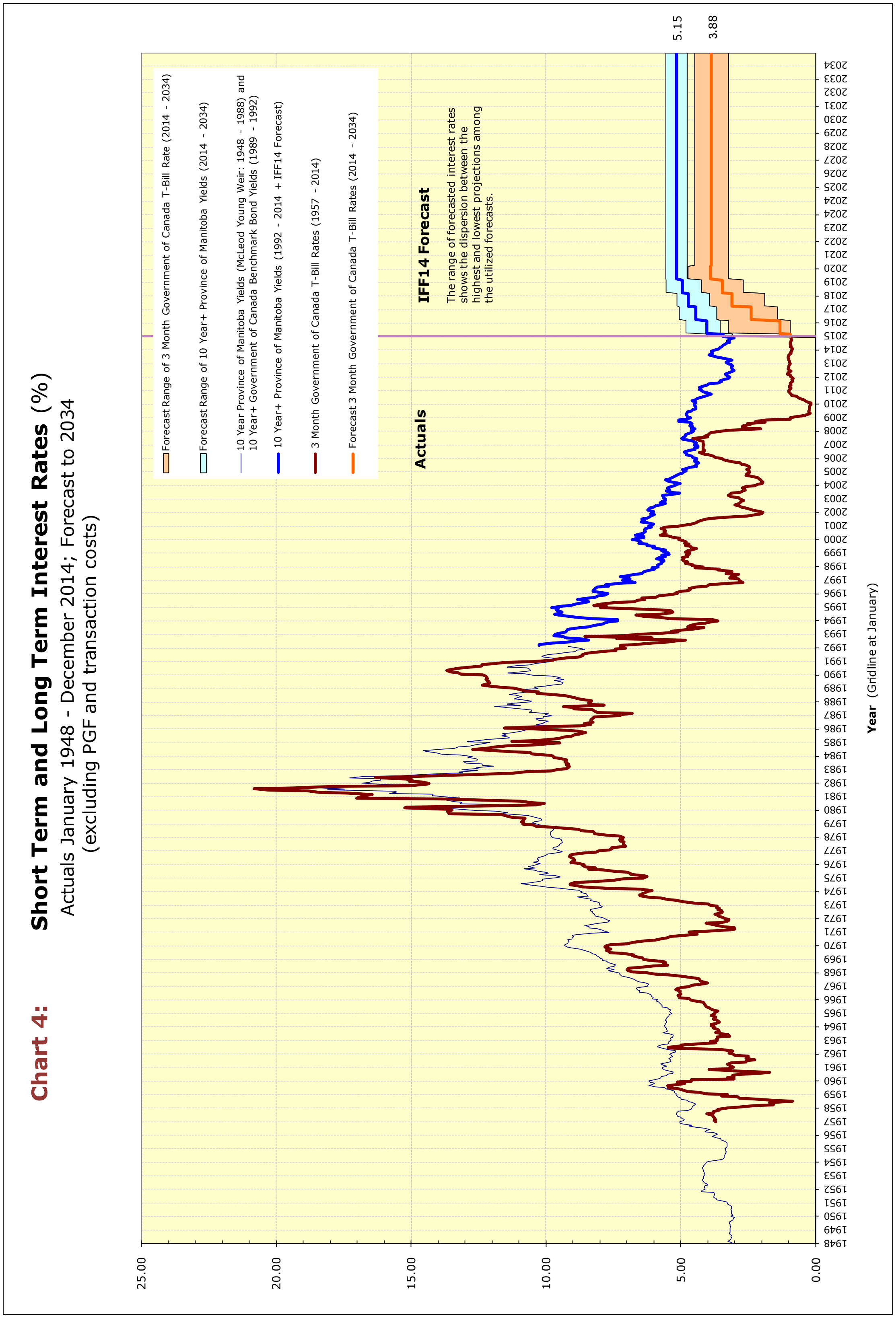


Chart 4:
Short Term and Long Term Interest Rates (%)
Actuals January 1948 - December 2014; Forecast to 2034
(excluding PGF and transaction costs)
Forecast Range of 3 Month Government of Canada T-Bill Rate (2014 - 2034)
Forecast Range of 10 Year+ Province of Manitoba Yields (2014 - 2034)
10 Year Province of Manitoba Yields (McLeod Young Weir: 1948 - 1988) and 10 Year+ Government of Canada Benchmark Bond Yields (1989 - 1992)
10 Year+ Province of Manitoba Yields (1992 - 2014 + IFF14 Forecast)
3 Month Government of Canada T-Bill Rates (1957 - 2014)
Forecast 3 Month Government of Canada T-Bill Rates (2014 - 2034)
Actuals
IFF14 Forecast
The range of forecasted interest rates shows the dispersion between the highest and lowest projections among the utilized forecasts.
5.15
3.88
Year (Gridline at January)
25.00
20.00
15.00
10.00
5.00
0.00

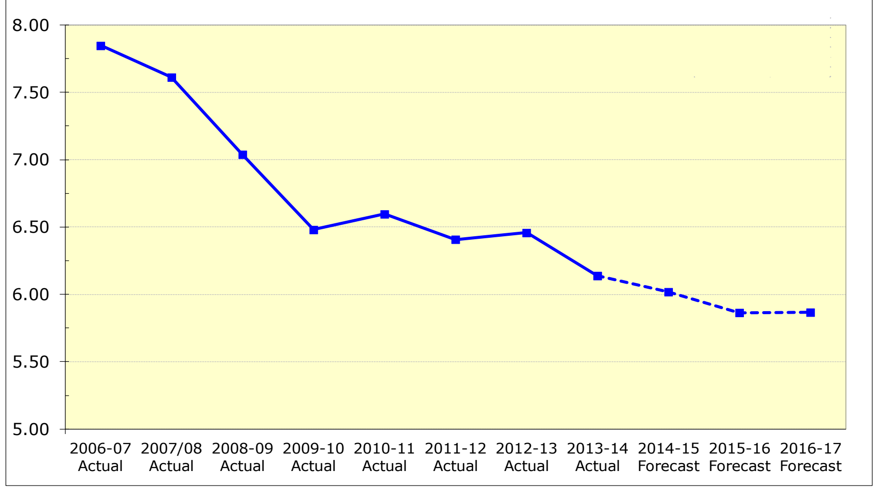
Chart 4 illustrates that for a prolonged period of time from the mid-1970's to the early 1990's, the long term interest rates for the Province of Manitoba were in excess of 10%, and in 1981 the long term interest rate exceeded 18%. The average 10 year+ interest rate in the April 1992 – July 2007 period before the financial crisis was slightly over 6.5%, while in the post-financial crisis period from August 2007 to December 2014 the average 10 year+ interest rate was slightly below 4.0%. Looking forward, the average 10 year+ interest rates are forecast to rise from their actual at December 31, 2014 of approximately 3.0% to the average consensus forecast of approximately 5.2% by 2019/20.

With respect to the interest rate environment for Manitoba Hydro's Canadian long term floating rate debt, historically there has been significant volatility in interest reset rates.[1] As compared to the 10 year+ interest rates, the average 3 month Canadian T-Bill interest rate (as a proxy for both the variable interest reset rates on Manitoba Hydro's portfolio of Canadian long term floating rate debt and Manitoba Hydro's short term interest rate) have had higher peaks and lower valleys, along with more intervening variability. Looking forward, by 2019/20 average consensus forecast for the 3 month T-Bill rate is projected to be approximately 3.9%.

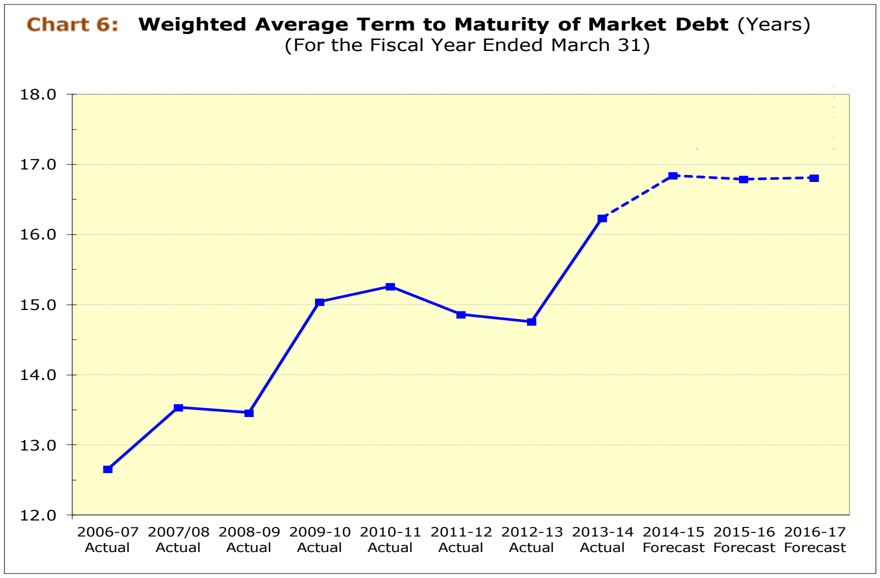
Although economic forecasts during the last few years have generally called for a quicker economic recovery and correspondingly higher interest rates, on an actual basis, the strength and pace of a recovery has been subdued. Manitoba Hydro will continue to monitor the financial markets, along with gathering the views of external economic forecasters in order to obtain the range and consensus forecast of their opinions.

The low interest rate environment over the past few years has provided the opportunity for Manitoba Hydro to secure stable, low cost funding. As shown on Chart 5, since 2006/07, the debt portfolio's **net weighted average interest rate has decreased** by nearly 2.0%. It is anticipated that this positive trend will continue until leveling off in 2016/17.

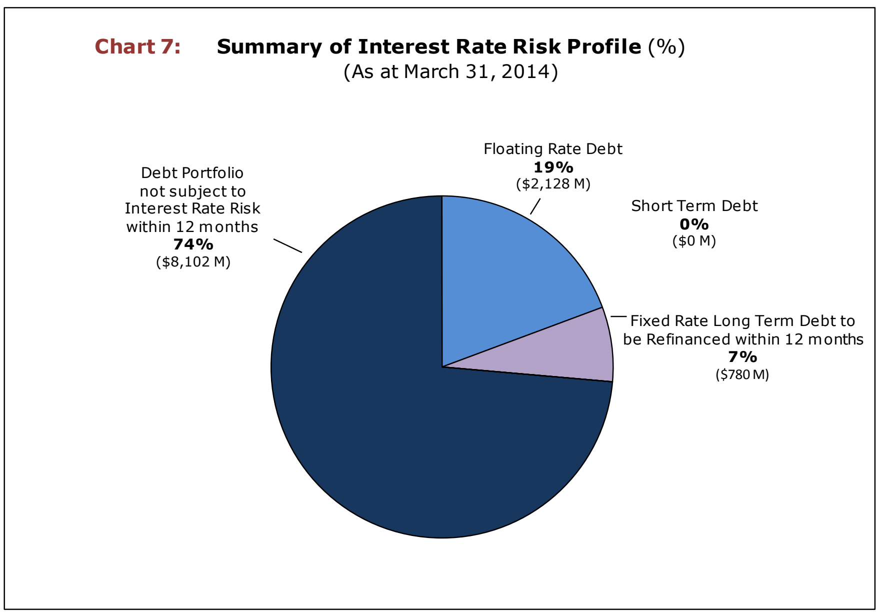
Chart 5: Weighted Average Interest Rate (%)
(For the Fiscal Year Ended March 31)



[1] The interest reset rate for Manitoba Hydro's portfolio of Canadian long term floating rate debt is typically the 3 month Bloomberg Bankers' Acceptance rate (CDOR03). The pricing for these long term floating rate debt issues also have a fixed rate margin that is added to the variable bankers' acceptance (BA) component. For example, on March 31, 2011 Manitoba Hydro secured long term debt series C121-3 for CAD $100 million and an April 19, 2016 maturity date. C121-3 bears a floating coupon rate of CDOR03 + 20 basis points. The coupon payment rate is reset on a quarterly basis to add the variable BA component to the 20 basis point fixed rate margin.



This opportunity to secure low cost financing is balanced alongside the debt management objective to provide stability. To enhance the debt portfolio stability, the **weighted average term to maturity of its market debt portfolio has increased** by over three years since 2006/07 (Chart 6). When selecting terms for its new borrowings, Manitoba Hydro gives careful consideration to the debt maturity schedule and the total level of annual financing requirements. In order to mitigate refinancing risk, to maintain financing flexibility during the upcoming decade, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term fixed rate financings with maturities of 10 years and longer. For Manitoba Hydro's new long term debt issuance in 2013/14, the term to maturity ranged from 3 – 50 years, with a weighted average term to maturity of 28 years.



Stability is also reinforced by carefully managing the aggregate interest rate risk within the debt portfolio. Manitoba Hydro's **interest rate policy** on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; to a maximum of 35% of the total debt portfolio. Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio. During years in which there are high levels of refinancings and/or new borrowings for prospective cash requirements, in order to manage the overall interest rate risk profile, the Corporation's interest rate risk on its existing debt portfolio may be reduced by decreasing the percentage of aggregated floating rate debt and short term debt to below 15% of the total debt portfolio. A graphical depiction of Manitoba Hydro's interest rate risk profile as at March 31, 2014 is as shown in Chart 7. During 2014/15, the interest rate risk on the existing debt portfolio will be reduced in order to accommodate the significant prospective capital borrowing requirements during 2015/16 and 2016/17. Consequenty, it is projected that the percentage of floating rate debt within the projected debt portfolio at March 31, 2015 will be approximately 15%.

Liquidity risk refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due. Manitoba Hydro will meet its financial obligations when due through cash generated from operations, short term borrowings, long term borrowings advanced from the Province of Manitoba, and where applicable, sinking fund withdrawals. Overall financing requirements of Manitoba Hydro and its subsidiaries are managed on a consolidated basis. The Corporation closely monitors its cash receipts and disbursements on a daily basis as part of regular cash balancing activities. The Corporation also monitors short term debt balances and forecasted cash requirements to ensure that it has sufficient cash to meet near term financial obligations as they come due. To support business continuity and enhance financing flexibility, the Corporation may maintain positive cash and/or investment balances.

The Manitoba Hydro Act grants the Corporation the power to issue short term borrowings in the name of the Manitoba Hydro-Electric Board up to a limit of $500 million and to have this debt unconditionally guaranteed as to principal and interest by the Province of Manitoba. Short term borrowings are considered to have terms to maturity of less than one year. The short term borrowing program is a credit facility with a primary objective to safeguard the Corporation from liquidity risk by providing sufficient liquidity for the Corporation's temporary cash requirements. Manitoba Hydro uses its short term debt line to fund its working capital requirements and to bridge the timing between long term debt issues. As Manitoba Hydro can issue promissory notes payable within its Commercial Paper Program at rates lower than the Prime or Base Rates, Manitoba Hydro typically issues promissory notes instead of relying on bank overdrafts to meet its temporary cash requirements.

Manitoba Hydro is legislated under the Manitoba Hydro Act to make sinking fund payments to the Province of Manitoba of not less than 1% of the principal amount of the outstanding debt on the preceding March 31, and 4% of the balance in the sinking fund at such date. Sinking funds are invested in highly rated government or corporate bonds, as well as money market instruments. Sinking fund withdrawals are applied towards the repayment of advances made to, and moneys borrowed by, the Corporation.

Manitoba Hydro has significant export revenues denominated in US dollars. As part of the Corporation's **foreign currency exchange risk management program**, in order to mitigate the foreign currency exchange risk on these revenues, Manitoba Hydro maintains a natural hedge with US dollar cash flows, including outflows from US denominated debt. At December 31, 2014 the portion of Manitoba Hydro's debt portfolio that was made up of US denominated debt principal was 13%. The US debt portfolio may occasionally be rebalanced in accordance with US dollar cash flows. In addition to the mitigation of foreign exchange risk, Manitoba Hydro considers a number of factors when determining whether it will seek US dollar versus Canadian dollar debt, including the cost effectiveness of executing a US dollar versus a Canadian dollar issuance for available terms, and the liquidity and interest rate benefits associated with broadened access to capital within a diversified investor base. Although provincial borrowers frequently issue long bonds in the Canadian capital markets, due to financial market conditions, provincial issuance of US dollar debt with terms greater than 10 years is unusual because the long end of the US curve has not been cost effective compared to Canada for many years.

6.0 Debt Management Activities

The following section provides an overview of Manitoba Hydro's recent actual financings, as well as the forecasted financing requirements for 2014/15, 2015/16 and 2016/17. Actual financings will vary from forecast. Actual financings will consider the timing, dollar value, denomination, and fixed versus floating nature of the issue depending on a number of factors including: the cash and liquidity requirements in existence at the time of financing; refinancing requirements on maturing debt and interest rate swaps; the term dependent on the current maturity schedule and forecasted borrowing requirements; interest rate expectations and the mitigation of interest rate risk; the management of foreign exchange risk; and the market appetite and economic environment.

2014/15 The actual and forecasted long term debt financings were as follows:

Quarter 1 During the first quarter, Manitoba Hydro secured long term debt financing totaling $856 million; of which $475 million was issued to finance new cash requirements and $381 million was for the refinancing of debt series FS-2A, FS-2B, FS-2C and FS-2D. A $100 million USD sinking fund withdrawal for the retirement of FS-1 on April 28, 2014 was also executed during this quarter.

Quarter 2 During the second quarter, Manitoba Hydro secured long term debt financing totaling $726.6 million; of which $387.4 million was issued to finance new cash requirements, $89.2 million was to fund HydroBond redemptions, and $250.0 million was for the refinancing of debt series FM-1, FM-2, FM-3 and FM-4.

Quarter 3 During the third quarter, Manitoba Hydro secured long term debt financing totaling $490 million; of which $200 million was for the refinancing of debt series FC-3, $40 million was for the refinancing of mitigation bond 5A, and $250 million was issued to finance new cash requirements. A currency swap to repatriate $200 million of USD principal into $228.38 million of CAD principal was also executed during this quarter for debt series EE.

Quarter 4 It is forecasted that $400 million of long term debt will be issued during this quarter for new cash requirements.

2015/16 The forecasted long term debt financing requirement is $2,400 million composed of the following:

- $2,088 million of long term debt for new cash requirements.
- $312 million to refinance maturing long term debt.

Manitoba Hydro will consider the availability of sinking fund withdrawals to reduce the required refinancing of maturing debt.

The long term debt financings forecasted for each quarter of this fiscal year are as follows:

Quarter 1 It is forecasted that $538 million of long term debt will be issued during this quarter for new cash requirements. In addition, the following refinancings are forecasted to occur in this quarter: a $50 million refinancing of floating rate debt issue C115 maturing May 4, 2015 and a $12 million refinancing of Winnipeg Hydro Bond 4K maturing May 12, 2015.

Quarter 2 It is forecasted that $600 million of long term debt will be issued during this quarter for new cash requirements.

Quarter 3 It is forecasted that $550 million of long term debt will be issued during this quarter for new cash requirements. In addition, the following floating rate debt refinancings are forecasted to occur this quarter: a $50 million refinancing of EY2 and a $200 refinancing of EY both maturing December 3, 2015.

Quarter 4 It is forecasted that $400 million of long term debt will be issued during this quarter for new cash requirements.

2016/17 The forecasted long term debt financing requirement is $3,200 million composed of the following:

- $2,866 million of long term debt for new cash requirements.
- $334 million to refinance maturing long term debt.

Manitoba Hydro will consider the availability of sinking fund withdrawals to reduce the required refinancing of maturing debt.

The long term debt financings forecasted for each quarter of this fiscal year are as follows:

Quarter 1 It is forecasted that $867 million of long term debt will be issued during this quarter for new cash requirements. In addition, the following refinancings are forecasted to occur in this quarter: a $100 million refinancing of floating rate debt issue C121-3 maturing April 19, 2016 and a $33 million refinancing of Hydrobonds maturing June 15, 2016.

Quarter 2 It is forecasted that $799.4 million of long term debt will be issued during this quarter for new cash requirements. In addition, the following refinancing is forecasted to occur in this quarter: a $200.6 million refinancing of floating rate debt issue AZ maturing July 17, 2016.

Quarter 3 It is forecasted that $400 million of long term debt will be issued during this quarter for new cash requirements.

Quarter 4 It is forecasted that $800 million of long term debt will be issued during this quarter for new cash requirements.

Rating Report

Report Date:
October 17, 2014

Previous Report:
October 11, 2013

DBRS

Insight beyond the rating.

Province of Manitoba

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The Province
Manitoba is located in Central Canada and ranks fifth among Canadian provinces by population and sixth in terms of GDP. The Province is home to significant renewable energy resources, with almost all electricity generated from water.

Treasury Bill Limit
$1.95 billion

Promissory Notes Limit
$750 million (excludes Manitoba Hydro)

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Long-Term Debt*	A (high)	Confirmed	Stable
Short-Term Debt*	R-1 (middle)	Confirmed	Stable

*Issued/guaranteed by the Province, including the Manitoba-Hydro Electric Board.

Rating Update

DBRS has confirmed the Issuer Rating and Long-Term Debt ratings of the Province of Manitoba (the Province or Manitoba) at A (high), along with its Short-Term Debt rating at R-1 (middle). The trend on all ratings is Stable. Improvement in fiscal performance has been slow, although Manitoba remains on track to restore balance by 2016–17, as presented last year. While debt has increased notably from pre-recession levels, it now appears to be stabilizing, aided by supportive economic conditions and stronger external demand.

For the fiscal year ended March 31, 2014, Manitoba reported a deficit of $522 million in its recently released public accounts. On a DBRS-adjusted basis, after including capital expenditures as incurred rather than as amortized, this translates into a shortfall of $1.3 billion, or 2.2% of GDP, compared with a deficit of $1.6 billion anticipated at the time of DBRS's last review. The better-than-expected performance was entirely due to lower-than-planned capital spending, while revenues rose by 4.5%, consistent with budget. As a result, total DBRS-adjusted debt grew by 7.2% to $23.1 billion, pushing the debt-to-GDP ratio to 38.2% from 36.9% a year earlier. This represents the fourth-highest debt burden among Canadian provinces. (Continued on page 2.)

Rating Considerations

Strengths
(1) Diversified and resilient economy
(2) Manageable debt burden and sound debt management practices
(3) Abundant low-cost hydroelectricity

Challenges
(1) Slow fiscal progress dependent on successful renewal of public sector collective agreements
(2) High reliance on federal transfers
(3) Below-average income and GDP per capita

Financial Information

	For the year ended March 31				
(all financial figures DBRS adjusted)	2014-15B	2013-14	2012-13	2011-12	2010-11
Debt* ($ millions)	24,142	23,057	21,515	19,840	17,478
Debt*/GDP	38.6%	38.2%	36.9%	36.0%	33.0%
Surplus (deficit) ($ millions)	(1,330)	(1,301)	(1,322)	(1,966)	(1,102)
Surplus (deficit)/GDP	(2.1%)	(2.2%)	(2.3%)	(3.6%)	(2.1%)
Interest costs/total revenue	5.5%	5.4%	5.6%	5.5%	5.4%
Federal transfers/total revenue	26.0%	27.2%	29.2%	31.8%	30.7%
Nominal GDP ($ millions)	62,514	60,400	58,245	55,169	52,896
Real GDP growth rate	2.2%	2.4%	2.6%	1.7%	2.6%
Unemployment rate	5.2%	5.4%	5.3%	5.4%	5.4%

* DBRS-defined: tax-supported debt + unfunded pension liabilities. B = Budget.
Source: Province of Manitoba, Statistics Canada, and DBRS calculations.

Province of Manitoba

Report Date:
October 17, 2014

Rating Update (Continued from page 1.)

Based on the current private sector consensus tracked by DBRS, real GDP is forecast to grow by 1.9% in 2014, which compares with the 2.2% assumed by Manitoba at budget time. However, for 2015, the private sector consensus looks somewhat stronger, pointing to real growth of 2.4%. A return to normal crop production will exert a modest drag on growth in 2014, but this is expected to subside the following year. In addition, investment activity is poised to regain some momentum heading into 2015, and an improving outlook for U.S. demand and a weaker Canadian dollar should be positive for exports and help to offset a soft domestic environment.

After experiencing a delay last year, Manitoba's target to restore fiscal balance by 2016–17 remains intact in the current budget. For 2014–15, a deficit of $357 million is projected, or $1.3 billion on a DBRS-adjusted basis. This equates to 2.1% of GDP – still one of the largest fiscal shortfalls among Canadian provinces. Aside from targeted tax credits for seniors and one to promote increased apprenticeship opportunities, this year's budget was devoid of any significant tax measures. Meanwhile, total spending is forecast to advance by 2.9% but will require sound fiscal discipline to help achieve targets. This includes limiting the growth in health-care spending to just 1.5% − an ambitious target. In this regard, the government has introduced a new lean council intended to enhance service delivery and workflow, although there are no specific savings targets associated with this initiative. Moreover, labour negotiations will be particularly important, with a number of collective agreements coming up for renewal. As a result, the debt-to-GDP ratio will continue to inch up to 38.6% in 2014–15 before stabilizing around 39% thereafter. This represents a slight improvement from the peak foreseen at the time of DBRS's last review and is considered manageable for the rating.

Rating Considerations Details

Strengths

(1) Manitoba has one of the most resilient and well-diversified economies in the country. This strength was evident during the 2009 downturn when the Province experienced only a very mild recession. The economy boasts a well-balanced mix of industries, including agriculture and mining, manufacturing, financial services and transportation and has one of the lowest unemployment rates in Canada. In addition, the composition of Manitoba's exports also tends to be more diverse than that of other provinces. As a result of these factors, the provincial economy shows less volatility than its manufacturing- and resource-dependent neighbours.

(2) As of March 31, 2014, Manitoba's debt burden stood at 38.2% of GDP, and, although it has been creeping up since 2009, it is comparable to levels seen in the late 1990s and remains manageable for the current ratings. The Province maintains a relatively smooth debt maturity profile, with no unhedged foreign currency debt (excluding Manitoba Hydro) and a moderate level of floating-rate debt, which adds stability to debt-servicing requirements.

(3) Manitoba benefits from an abundance of low-cost hydroelectricity, resulting in some of the lowest electricity rates in North America. This gives the Province a distinct advantage when competing for new business investment. The 214 megawatt (MW) Wuskwatim dam project was completed in 2012, further adding to Manitoba's supply of hydroelectricity. In addition, the Keeyask generating station (695 MW for $6.5 billion) is moving forward with an anticipated in-service date of 2019, and Conawapa (1,485 for $10.7 billion) is also being considered but will be dependent on growth in domestic demand and Manitoba Hydro's ability to secure export contracts. DBRS notes that the relatively recent expansion of shale gas extraction has altered the competitive landscape by increasing the supply of low cost energy and may slow Manitoba's appetite for further development.

Challenges

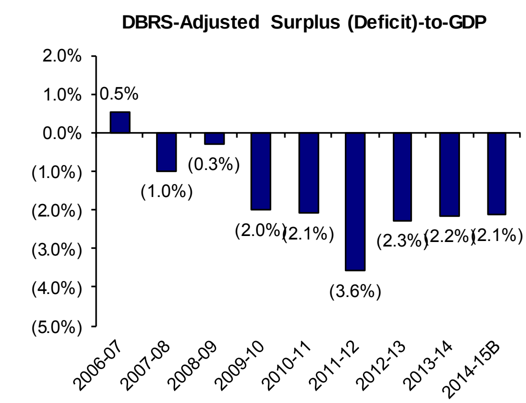
(1) With a return to balance not anticipated until 2016–17, Manitoba's fiscal recovery plan is one of the slowest recovery plans among Canadian provinces even though the depth of the recession was relatively mild. On a DBRS-adjusted basis, Manitoba's deficit has been equal to 2.0% of GDP or greater for five consecutive years, and this is expected to continue in 2014–15. Furthermore, adherence to fiscal targets will be dependent on the

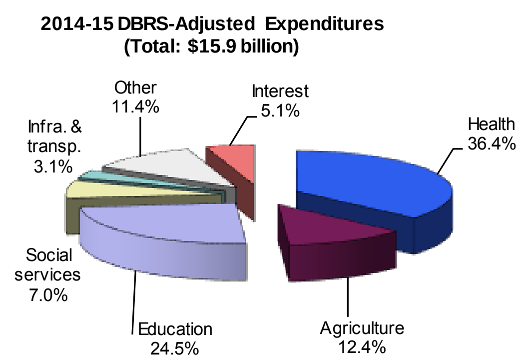
successful renewal of a number of collective agreements, including those with teachers and civil servants, which may be challenging in an environment of improving economic conditions.

(2) Despite its relatively resilient economy, Manitoba receives approximately 27% of its revenues by way of federal transfers, including roughly 13% from equalization, leaving it exposed to changes in federal transfer programs. This represents the highest reliance on federal revenues outside of Atlantic Canada.

(3) Manitoba boasts a well-diversified economy and healthy labour market; however, it continues to exhibit below-average wealth. The Province recorded primary household income per capita of $30,417 in 2012 (the latest year for which information is available), below the national average of $34,210. Manitoba also generates below-average GDP per capita, suggesting that productivity and high-value-added sectors may be lagging.

2014-15 Budget





After experiencing a delay last year, Manitoba's target to restore fiscal balance by 2016–17 remains intact in the current budget. For 2014–15, a deficit of $357 million is projected, or $1.3 billion on a DBRS-adjusted basis (after including capital expenditures as incurred rather than as amortized). This is consistent with the deficit realized in 2013–14 and equates to 2.1% of GDP – still one of the largest fiscal shortfalls among Canadian provinces.

For 2014–15, the Province's revenue forecast is based on nominal GDP growth of 3.5%, which is expected to contribute to a 2.9% increase in total DBRS-adjusted revenues. Aside from targeted tax credits for seniors and one to promote increased apprenticeship opportunities, this year's budget was devoid of any significant tax measures. Nonetheless, tax revenues are projected to rise by close to 10.0% year over year, buoyed by an 8.8% increase in sales tax receipts, reflecting the full-year impact of the 1% rate adjustment – to 8% − implemented last year. Personal and corporate income taxes are also forecast to rise by 4.2% and 7.1%, respectively. However, reduced earnings at government business enterprises and a modest decline in federal transfers will provide a partial offset.

Similar to revenues, DBRS-adjusted total spending is forecast to advance by 2.9% but will require sound fiscal discipline to help achieve targets. In this regard, the government has introduced a new lean council intended to enhance service delivery and workflow, although there are no specific savings targets associated with this initiative. Labour negotiations will be particularly important, as a number of collective agreements are due to be renegotiated, including those with teachers and civil servants. Of note, the government continues to reduce the size of the civil service and is over halfway toward its target of a reduction in 600 (headcount). Of the key program areas, education will see the largest increase, rising by 9.4%, as the Province continues to target smaller class sizes. Meanwhile, health and social services will be limited to 1.5% and 3.8% growth, respectively. To contain health care costs, the Province is continuing with efforts to amalgamate the regional health authorities, better coordinate primary care and, where possible, move to generic drugs.

Nonetheless, an aging and growing population and general increases in demand for services is going to make achieving this target a challenging task. Most other program areas will see relatively flat or declining budget allocations. Gross capital spending is projected to rise by 16.5%, although DBRS notes that this is an area that is often underspent. Interest charges, net of sinking fund earnings, are projected to rise by 5.8%, reflective of Manitoba's growing debt burden, but DBRS notes that the currently low interest rate environment is likely to result in some savings in this area.

Outlook

First quarter results released on September 30, 2014, indicate that fiscal performance is tracking slightly ahead of plan. Stronger performance at government business enterprises has helped to boost revenues by $41 million, while underspending of $46 million is largely attributed to timing. However, DBRS notes that subsequent to the first quarter, the Province authorized $100 million in additional spending related to summer floods not yet incorporated in the above results. While mitigation efforts are being sought, this highlights the still challenging task of restoring fiscal balance.

Manitoba's medium-term fiscal outlook forecasts a deficit of $218 million in 2015–16, followed by small surpluses in both 2016–17 and 2017–18. On a DBRS-adjusted basis, deficits are expected to range between 1.0% and 1.8% of GDP over the forecast horizon but will require prudent fiscal discipline and a supportive economic backdrop if these targets are to be achieved.

2013–14 Results

For the fiscal year ended March 31, 2014, public accounts reported a deficit of $522 million. On a DBRS-adjusted basis, this translates into a shortfall of $1.3 billion, or 2.2% of GDP, compared with a deficit of $1.6 billion anticipated at the time of DBRS's last review. The better-than-expected performance was entirely due to lower-than-planned capital spending.

In 2013–14, total DBRS-adjusted revenues grew by 4.5% year over year, in line with budget. An increase in sales tax receipts was the primary driver as a result of last year's decision to raise the provincial rate to 8% from 7%, which took effect in July 2013. This boosted sales taxes by 14.8% from 2012–13. Corporate income tax was up by 6.0%, largely owing to favourable prior year adjustments. Results were also strong at Manitoba Hydro, as it reported its highest net income since 2008–09, owing to increased demand and prices during a cold winter. Federal transfers were an area of weakness, as they declined by 2.8% year over year as a result of a combination of lower equalization payments and other cost shared programs.

DBRS-adjusted spending growth was limited to 4.0% in 2013–14, helped by gross capital spending that came in $332 million below budget. Health-care costs advanced by 4.6%, driven by inflationary pressures at the regional health authorities. Meanwhile, education costs grew by 6.7%, partly driven by the government's initiative to fund smaller class sizes and also higher pension costs as a result of required increases in employer contributions. Volume and price pressures contributed to increases in social services by 3.8%. During the year, the Province also set aside $100 million in provisions for a flood settlement with First Nations communities related to long-standing claims.

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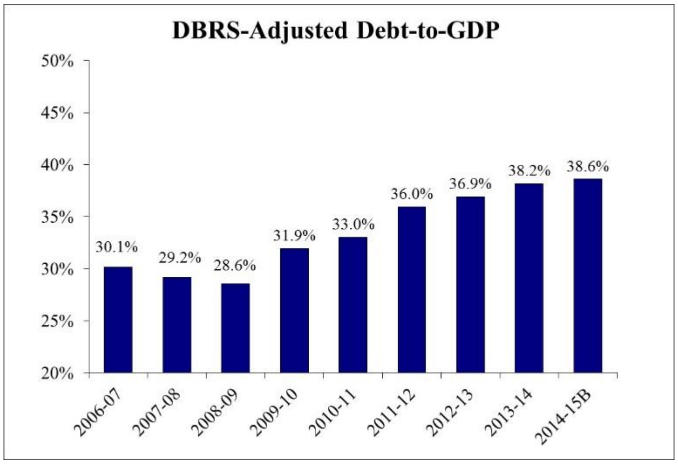
Debt Profile



In 2013–14, total DBRS-adjusted debt (defined as tax-supported debt plus unfunded pension liabilities) grew by 7.2% to \$23.0 billion. This was somewhat faster than expected, driven by increased debt at crown corporations and municipalities as well as faster growth in unfunded pension liabilities that were only partly offset by lower-than-planned capital spending. As a result, this boosted the debt-to-GDP ratio to 38.2% from 36.9% a year earlier and represents the fourth-highest debt burden among Canadian provinces.

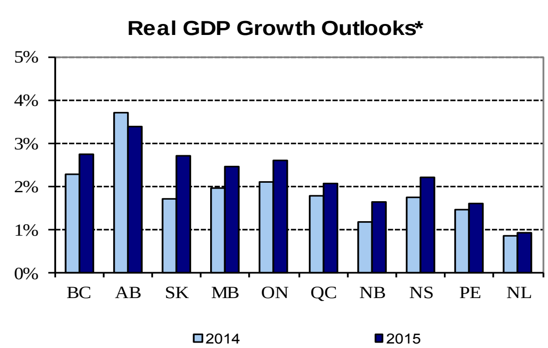
Manitoba boasts sound debt management practices with a relatively smooth debt maturity profile. As of March 31, 2104, the Province had no unhedged foreign currency debt (aside from Manitoba Hydro) and floating-rate debt comprised only 15% of total debt. This adds stability to borrowing costs, which accounted for only 5.4% of total revenues in 2013–14.

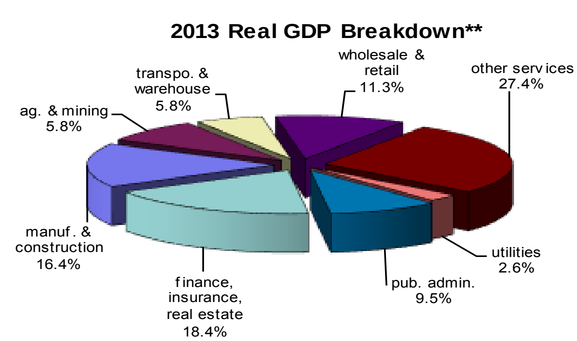
Outlook

For 2014–15, debt is expected to grow by a further \$1.1 billion, or 4.7%, driven by the fiscal deficit and capital spending in excess of amortization. As such, debt-to-GDP will continue to inch up to 38.6%. Gross borrowing requirements are forecast at \$4.8 billion and comprise \$2.4 billion in refinancing needs, \$842 million for fiscal shortfall and capital needs, and the remainder for crown corporations, largely Manitoba Hydro. At the time of writing, approximately \$3.3 billion, or 70%, of borrowing needs had been fulfilled.

Based on the Province's medium-term plan, debt is expected to continue growing between 3% and 6% annually until 2017–18. This should result in Manitoba's debt burden stabilizing around 39% of GDP, a slight improvement from the peak foreseen at the time of DBRS's last review and considered manageable for the rating.

Economy





*Based on major Canadian banks' forecasts at the time of this report. **Statistics Canada, CANSIM379-0028.

Manitoba's economy continued to outperform the national average in 2013, with real GDP advancing by 2.4%. A strong agricultural sector was a key contributor, owing to favourable weather conditions and a bumper crop. In addition, increased activity in the oil sector helped to offset declines in base metal production, while electricity generation showed improvement aided by a full year of production from the new Wuskwatim generating facility. According to Statistics Canada's survey of private and public investment intentions (PPI survey), non-residential construction, machinery and equipment investment was also strong, rising by 8.0% in

2013 – well above the national average. Population growth was relatively sound, supported by international immigration and, when combined with a low interest rate environment, helped to propel housing starts to their highest level since the late 1980s. However, employment growth was somewhat soft, as gains in private sector employment, particularly in agriculture, were mostly offset by reductions in the public sector. Nevertheless, the unemployment rate remained relatively steady at 5.4% – the third lowest among Canadian provinces.

Outlook

Based on the current private sector consensus tracked by DBRS, real GDP is forecast to grow by 1.9% in 2014, which compares with the 2.2% assumed by Manitoba at the time of the budget. The investment climate appears to be somewhat soft, with Statistics Canada's PPI survey pointing to a slight decline in non-residential construction, machinery and equipment spending. Similarly, residential investment is likely to slow, as CMHC forecasts a 14.3% decline in housing starts following a very strong 2013. The outlook for agricultural output appears favourable although unlikely to repeat last year's solid performance. There are also signs that oil production, which has been a major driver of growth in recent years and now accounts for 2.5% of real GDP, may be reaching a plateau absent any significant new discoveries. As of August, Manitoba's unemployment rate stood at 5.5% (seasonally adjusted), up from 5.3% during the same period a year ago and remains above the budget estimate. Retail trade is up by 5.3% (seasonally adjusted) as of July 2014 compared with the prior year, and this is above the national average advance of 5.0%. Encouragingly, export markets are expected to provide an offset to domestic softness, supported by a weaker Canadian dollar and improving U.S. demand.

For 2015, the private sector consensus points to real GDP growth of 2.4%, in line with budget estimates. With a return to normal crop production in 2014, this will no longer be a drag in 2015, and investment is also expected to regain some momentum. Economic risks are considered to be more balanced relative to last year's forecast, providing greater confidence that improving economic conditions will be sustained and supportive of Manitoba's fiscal targets.

Economic Statistics	For the year ended December 31						
	2015P	2014P	2013	2012	2011	2010	2009
Nominal GDP ($ millions)	65,265	62,514	60,400	58,245	55,169	52,896	50,636
Nominal GDP growth	4.4%	3.5%	3.7%	5.6%	4.3%	4.5%	(2.5%)
Real GDP growth	2.4%	2.2%	2.4%	2.6%	1.7%	2.6%	(0.2%)
Population (thousands)	1,296	1,282	1,265	1,250	1,234	1,221	1,209
Population growth	1.1%	1.3%	1.2%	1.4%	1.0%	1.0%	0.9%
Employment (thousands)	648	640	633	630	625	620	608
Unemployment rate	5.0%	5.2%	5.4%	5.3%	5.4%	5.4%	5.2%
Housing starts (units)	6,500	6,400	7,465	7,242	6,083	5,888	4,174
Retail sales ($ millions)	18,739	18,028	17,297	16,652	16,443	15,770	14,920
Inflation rate (CPI)	1.9%	1.8%	2.2%	1.6%	3.0%	0.8%	0.6%
Household income per capita ($)	32,867	31,563	31,000	30,417	29,324	28,260	27,814

Sources: Statistics Canada (actuals); Manitoba Finance and DBRS estimates; CMHC (housing projections). P= Projected. n.a. = not available.

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Budget Summary* ($ millions)	Budget 2014-15	2013-14	Budget 2013-14	2012-13	2011-12	2010-11
Revenue	14,561	14,152	14,146	13,540	13,621	13,173
Program expenditure	15,088	14,694	15,004	14,097	14,839	13,569
Program surplus (deficit)	(527)	(542)	(858)	(557)	(1,218)	(396)
Interest expense	803	759	776	765	748	706
DBRS-Adjusted Surplus (Deficit)	(1,330)	(1,301)	(1,635)	(1,322)	(1,966)	(1,102)
DBRS adjustments:						
Capital expenditures less amortization	973	779	1,117	762	965	923
Other non-recurring items, incl. assets sales	-	-	-	-	-	-
Surplus (deficit), as reported	(357)	(522)	(518)	(560)	(1,001)	(179)
Tax-supported debt + unfunded pension liabilities	24,142	23,057	22,392	21,515	19,840	17,478
Gross borrowing requirements (all entities)	4,766	4,528	4,753	3,493	5,424	3,550
Gross capital expenditure	1,553	1,333	1,665	1,273	1,441	1,361

* DBRS adjusts reported figures to exclude certain non-recurring items (e.g. asset sales). DBRS also recognizes capital expenditures as incurred, rather than as amortized, to improve inter-provincial comparability.

Selected Financial Indicators (DBRS-Adjusted)						
Debt*/GDP	38.6%	38.2%	37.3%	36.9%	36.0%	33.0%
Surplus (deficit)/GDP	(2.1%)	(2.2%)	(2.7%)	(2.3%)	(3.6%)	(2.1%)
Surplus (deficit)/total revenue	(9.1%)	(9.2%)	(11.6%)	(9.8%)	(14.4%)	(8.4%)
Interest costs/total revenue	5.5%	5.4%	5.5%	5.6%	5.5%	5.4%
Total tax revenues/total revenue	54.0%	50.7%	52.3%	49.2%	47.6%	48.0%
Federal transfers/total revenue	26.0%	27.2%	27.3%	29.2%	31.8%	30.7%
Program expenditures/total revenue	103.6%	103.8%	106.1%	104.1%	108.9%	103.0%
Health expenditures/total expenditures	36.4%	36.9%	35.9%	36.7%	34.2%	35.3%
Program expenditure growth	2.7%	4.2%	4.8%	(5.0%)	9.4%	5.0%
Total expenditure growth	2.8%	4.0%	4.7%	(4.7%)	9.2%	5.0%
Total revenue growth	2.9%	4.5%	3.0%	(0.6%)	3.4%	4.7%

* DBRS-defined: tax-supported debt + unfunded pension liabilities.

Background Political Information

Party in power:	New Democratic Party	Legislature seats:	35 of 57
Premier:	Greg Selinger	Election to be held by:	October 2015*

*If a federal election is held within two weeks of this date, the provincial election will be postponed until April 2016.

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Revenue ($ millions)	Budget 2014-15	2013-14	Budget 2013-14	2012-13	2011-12	2010-11
Personal income tax	3,102	2,978	2,953	2,846	2,697	2,592
Retail sales tax	2,207	2,028	2,047	1,767	1,658	1,618
Corporate taxes	1,096	1,024	966	965	919	824
Gasoline & motive fuel tax	340	329	326	332	269	256
Tobacco taxes	286	272	283	252	249	234
Education property tax (1)	701	434	676	380	554	690
Energy, mining, and other taxes	131	105	130	124	142	114
Total tax revenue	7,864	7,169	7,381	6,667	6,488	6,328
Lottery income (2)	575	554	615	298	338	332
Liquor control commission (2)	-	-	-	261	254	251
Manitoba Hydro	62	174	72	92	61	150
Natural resource levies	178	176	170	168	187	169
Fees, permits, licences, & other	2,089	2,237	2,031	2,102	1,961	1,896
Total Own-Source Revenue	10,768	10,310	10,270	9,587	9,289	9,126
Equalization payments	1,750	1,799	1,799	1,872	1,942	2,001
Canada health & social transfer	1,610	1,524	1,564	1,487	1,417	1,365
Other federal transfers	433	519	513	594	973	681
Total Federal Transfers	3,793	3,842	3,876	3,953	4,332	4,047
DBRS-Adjusted Revenue	14,561	14,152	14,146	13,540	13,621	13,173
Expenditures ($ millions)						
Health	5,791	5,706	5,689	5,454	5,328	5,044
Education and training	3,895	3,562	3,786	3,339	3,389	3,330
Social services (3)	1,115	1,074	1,069	1,035	1,013	978
Justice	542	534	521	500	460	435
Infrastructure and transportation	500	501	498	540	525	540
Agriculture, economic, & resource dev. (3)	1,977	1,914	1,985	1,883	2,209	1,860
Other general government	444	624	489	584	950	459
Capital expenditures less amortization (4)	973	779	1,117	762	965	923
Other	(150)	-	(150)	-	-	-
DBRS-Adjusted Program Expenditures	15,088	14,694	15,004	14,097	14,839	13,569
DBRS-Adjusted Program Surplus (Deficit)	(527)	(542)	(858)	(557)	(1,218)	(396)
Net interest expense (5)	803	759	776	765	748	706
DBRS-adjusted Expenditures	15,891	15,453	15,780	14,862	15,587	14,275
DBRS-Adjusted Surplus (Deficit)	(1,330)	(1,301)	(1,635)	(1,322)	(1,966)	(1,102)
DBRS adjustments:						
Capital expenditures less amortization (4)	973	779	1,117	762	965	923
Non-recurring revenue (expenditure)	-	-	-	-	-	-
Surplus (deficit), as reported	(357)	(522)	(518)	(560)	(1,001)	(179)

(1) For 2012-13 and 2013-14 actual results, education property tax is now reported net of tax credits. As a result, figures are not directly comparable with budget or for years 2011-12 and prior.

(2) In budget 2013-14, the Manitoba Lotteries Commission was merged with the Manitoba Liquor Control Commission.

(3) Due to government reorganization, budget and projected results in social services and agriculture, economic & resource development are not directly comparable with reported results for 2010-11 and prior years.

(4) This adjustment converts capital expenditures to a pay-as-you-go basis.

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Balance Sheet (Consolidated Statement)

($ millions)	As at March 31				As at March 31		
Financial Assets	2014	2013	2012	**Liabilities**	2014	2013	2012
Cash and cash equivalents	1,802	1,522	1,579	A/P and accrued charges	4,043	3,862	3,936
Amounts receivable	1,548	1,661	1,647	Debt (1)	32,662	30,602	28,742
Loans & advances (1)	11,828	10,871	10,050	Unamortized for. exch. fluc.	(33)	(39)	(44)
Equity in gov't enterprises	3,820	3,766	3,617	Unfunded pension liability	2,038	1,828	1,634
Net tangible capital assets	10,599	9,842	9,097	Other liabilities	-	-	-
Other assets	2,488	2,655	2,934	**Total Liabilities**	38,710	36,253	34,268
Total Financial Assets	32,085	30,317	28,924	**Accumulated Deficit**	(6,625)	(5,936)	(5,344)
				Total Liabilities	32,085	30,317	28,924

Net Public Sector Debt*

($ millions)	2015B	2014	2013	2012	2011	2010	2009	2008
	As at March 31							
Net general purpose debt	16,275	15,730	14,851	13,956	11,907	10,949	9,739	9,208
Crown corporation & gov't agencies	2,583	2,512	2,246	1,926	1,641	1,478	1,341	1,269
Schools and universities	620	590	538	495	461	432	384	387
Health facilities	1,477	1,262	1,149	1,094	1,015	949	831	833
Municipalities (2)	926	926	903	735	723	602	544	476
Net Tax-Supported Debt	21,881	21,019	19,687	18,206	15,747	14,410	12,839	12,174
Self-supporting debt:								
Manitoba Hydro	12,390	10,835	9,609	8,999	8,362	7,730	7,499	6,794
Total net public sector debt	34,271	31,855	29,296	27,205	24,109	22,140	20,338	18,968
Unfunded Pension Liabilities (3)	2,261	2,038	1,828	1,634	1,731	1,768	1,991	2,209
Per Capita (CAD) (3)								
Tax-supp. debt + unf. pension liabilities	18,831	18,221	17,205	16,082	14,316	13,386	12,382	12,093
Total public sector debt	26,732	25,174	23,427	22,051	19,747	18,319	16,980	15,948
As a % of GDP (3)								
Tax-supp. debt + unf. pension liabilities	38.6%	38.2%	36.9%	36.0%	33.0%	31.9%	28.6%	29.2%
Total public sector debt	54.8%	52.7%	50.3%	49.3%	45.6%	43.7%	39.2%	38.5%
Debt Breakdown by Currency (4)								
Cdn$ pay	n/a	100%	100%	100%	100%	100%	100%	100%
Non-CAD pay	n/a	0%	0%	0%	0%	0%	0%	0%
Fixed/Floating Rate Debt Breakdown (4)								
Fixed rate	n/a	85%	77%	80%	76%	82%	80%	81%
Floating rate	n/a	15%	23%	20%	24%	18%	20%	19%

Unfunded Pension Liabilities (Tax-Supported) ($ millions)	Valuation Date	Mar. 31, 2014
Civil service (5)	Dec. 2012	2,527
Teachers (5)	Jan. 2012	3,152
Other plans (includes MLAs, judges, other)	Various	1,765
	Total liabilities:	7,444
	Less pension assets:	5,406
	Total Unfunded Pension Liabilities:	2,038

Gross Debt Maturity Profile

Public Sector Debt	($ millions)	%
2014-15	4,224	13.0%
2015-16	2,066	6.4%
2016-17	2,601	8.0%
2017-18	2,513	7.7%
2018-19	2,712	8.3%
2019-20 to 2023-24	6,421	19.7%
2024-25+	11,993	36.9%
Total	32,529	100%

* Net of sinking fund and Debt Retirement Fund assets. B = Budget; n/a = not applicable.
(1) Includes asset and liability items related to debt of The Manitoba Hydro-Electric Board and Manitoba Lotteries Corporation.
(2) Not guaranteed by the Province. DBRS estimate for 2014; 2015B.
(3) Excludes pension liabilities of self-supporting Crown corporations.
(4) Net of hedges (if any). Floating rate debt is defined as debt that matures or is repriced within 12 months.
(5) Civil Service includes amounts for indexation and unamortized pension adjustment; Teachers includes amount for indexation.

Province of Manitoba

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Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Long-Term Debt*	A (high)	Confirmed	Stable
Short-Term Debt*	R-1 (middle)	Confirmed	Stable

*Issued/guaranteed by the Province, including the Manitoba-Hydro Electric Board.

Rating History

	Current	2013	2012	2011	2010	2009
Issuer Rating	A (high)	A (high)	A (high)	NR	NR	NR
Long-Term Debt	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Debt	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Related Research

- Rating Canadian Provincial Governments, September 2014.
- DBRS Updates Provincial Government Fact Sheet, October 10, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report
Report Date:
October 23, 2014
Previous Report:
September 16, 2013

Insight beyond the rating.

The Manitoba Hydro-Electric Board

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The Utility
The Manitoba Hydro-Electric Board (the Utility), a wholly owned Crown corporation of the Province of Manitoba, is a vertically integrated electric utility that provides generation, transmission and distribution of electricity to approximately 555,760 customers throughout Manitoba and natural gas service to approximately 272,228 customers via its subsidiary, Centra Gas Manitoba Inc. The Utility also exports electricity to more than 23 electric utilities through its participation in four wholesale markets in Canada and in the midwestern United States.

Short-Term Promissory Notes Programme
$500 million

Ratings

Debt	Rating	Rating Action	Trend
Long-Term Obligations	A (high)	Confirmed	Stable
Short-Term Obligations	R-1 (middle)	Confirmed	Stable

Note: These Obligations are based on the status of Manitoba Hydro-Electric Board as a Crown agent of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

Rating Update

On October 17, 2014, DBRS confirmed the Issuer Rating and Long-Term Debt rating of the Province of Manitoba (the Province) at A (high) and its Short-Term Debt rating at R-1 (middle), all with Stable trends (see DBRS press release, "DBRS Confirms Province of Manitoba at A (high) and R-1 (middle)," dated October 17, 2014). Consequently, the ratings of the Manitoba Hydro-Electric Board (Manitoba Hydro or the Utility) were confirmed, as the ratings of the Utility are a flow-through of the ratings of the Province. Pursuant to *The Manitoba Hydro Act*, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt (see the *DBRS Criteria: Guarantees and Other Forms of Explicit Support* methodology for further details). The Province also provides most of the Utility's financing through provincial advances (approximately 97% of total debt as at March 31, 2014).

Manitoba Hydro is currently undergoing a period of significant capital expenditure (capex) to increase generating capacity and to improve the reliability of its system. On July 2, 2014, the Province released the Public Utilities Board's (PUB) *Report on the Needs For and Alternatives To (NFAT): Review of Manitoba Hydro's Preferred Development Plan*. The NFAT report recommended that the Province and the Utility proceed with the 695 megawatt (MW) Keeyask Infrastructure and Generating Station Projects (Keeyask Project; approximately $6.5 billion) and the Manitoba-Minnesota Transmission Project (approximately $350 million), but stop spending on the 1,485 MW Conawapa Generating Station (approximately $10.7 billion) and the North-South Transmission Upgrade Project (approximately $500 million). The Province accepted these recommendations but also noted that the Conawapa Generating Station may be brought back for independent review in the future if an improved business case with more confirmed export sales can be made.

The large projects at Manitoba Hydro, including the Keeyask Project and the Bipole III Transmission Reliability Project (Bipole III; approximately $4.6 billion), will likely result in negative free cash flows for the Utility over the medium term and require substantial external funding. The Utility is expected to finance any cash shortfalls through advances from the Province. DBRS expects the Utility's key financial ratios to remain relatively flat as expected rate increases should improve cash flow and service debt obligations.

Rating Considerations

Strengths
(1) Debt is a direct obligation of the Province
(2) Low-cost hydro-based generation
(3) Access to favourable export markets

Challenges
(1) Hydrology risk
(2) High leverage
(3) High level of planned capex

Financial Information

The Manitoba Hydro-Electric Board	**For the year ended March 31**				
(CA$ millions where applicable)	**2014**	**2013**	**2012**	**2011**	**2010**
Total debt in capital structure (1)	79.4%	78.5%	77.9%	77.2%	77.0%
Cash flow/Total debt	6.4%	6.1%	6.3%	7.1%	7.6%
EBIT gross interest coverage (times)	0.95	0.89	0.80	1.00	1.01
Net income before non-recurring items	178	92	61	150	163
Cash flow from operations	690	589	567	595	589

(1) Adjusted for other comprehensive income.

The Manitoba Hydro-Electric Board

Report Date:
October 23, 2014

Rating Considerations Details

Strengths

(1) **Debt is a direct obligation of the Province.** Manitoba Hydro is an agent of the Crown and its debt securities, except for $65 million of Manitoba Hydro-Electric Board Bonds (less than 1% of total debt at March 31, 2014), are held or guaranteed by the Province; therefore, the ratings assigned to Manitoba Hydro's obligations are a flow-through of the ratings assigned to the Province.

(2) **Low-cost hydro-based generation.** Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened capex requirements.

(3) **Access to favourable export markets.** Manitoba Hydro's interconnections (approximately 43% of installed capacity), with firm export transfer capability of 2,100 MW to the United States, 150 MW to Saskatchewan and 200 MW to Ontario, along with additional non-firm transfer capability, provide the Utility with access to favourable export markets. The interconnections also provide a secure supply of electricity for domestic customers during times of poor hydrology.

Challenges

(1) **Hydrology risk.** Given that approximately 92% of Manitoba Hydro's installed generating capacity is hydroelectricity-based, earnings and cash flows are highly sensitive to hydrological conditions. The Utility is also exposed to significant price and volume risk because of its export commitments under the fixed price-to-volume contract, which may require the Utility to procure power supply from import markets if hydrological conditions are unfavourable.

(2) **High leverage.** Manitoba Hydro's leverage (79.4% as at March 31, 2014) remains one of the highest among government-owned integrated utilities in Canada, limiting its financial flexibility going forward. The Utility's leverage is also expected to increase modestly for the medium term because of the significant amount of planned capex.

(3) **High level of planned capex.** The need to refurbish aging infrastructure, combined with the aggressive development of new hydro generation and transmission facilities, will require Manitoba Hydro to deploy significant capital into its electricity infrastructure over the medium term. The Utility has forecast that capex over the medium term should average approximately $2 billion per year, which will pressure the already-high debt levels.

Major Projects (Under Construction and Planned)

Project	Estimated Cost ($ millions)	Planned Construction Start Date	In-Service Target Date
Bipole III Transmission Reliability Project	4,600	2013/2014	2018
Keeyask Infrastructure and Generating Station Projects	6,500	2014	2019/2020
Manitoba-Minnesota Transmission Project	350	2015/2016	mid-2020

- **Bipole III:** This project involves the construction of a 500 kilovolt (kV) high voltage direct current transmission line, along with new converter stations. Construction began over winter 2013/2014 and the transmission line is expected to be in service for 2018.
- **Keeyask Project:** This project includes the development of a 695 MW generation station on the Nelson River. Construction began in July 2014 with the first generator expected to be in service for 2019 and the remaining units to be in service by 2020.
- **Manitoba-Minnesota Transmission Project:** This proposed project involves the construction of a 500 kV alternating current transmission line from Winnipeg to the Manitoba-Minnesota border, where it will connect to the Great Northern Transmission Line to be built by Minnesota Power. The Province authorized Manitoba Hydro to proceed with the project in July 2014 and the Utility will file an environmental impact statement in 2015. This project is subject to regulatory approval by federal and provincial environmental processes.
- **Conawapa Generating Station:** This project is a 1,485 MW generating station to be built on the Lower Nelson River. The Province announced in July 2014 that study and planning on this project have been suspended at this time following the release of the PUB's NFAT report. The Province noted that this project may be brought back for independent review in the future if an improved business case with more confirmed export sales can be made.

The Manitoba Hydro-Electric Board

Report Date:
October 23, 2014

Earnings and Outlook

(CA$ millions where applicable)	2014	2013	2012	2011	2010
	For the year ended March 31				
Total electricity revenues	1,878	1,733	1,573	1,616	1,583
Net gas revenues	163	147	132	143	138
Total revenues	2,041	1,880	1,705	1,759	1,721
EBITDA	1,065	991	865	968	957
EBIT	623	568	484	575	573
Gross interest expense	654	636	603	573	569
Earning before taxes	156	79	61	150	163
Net income before non-recurring items	178	92	61	150	163
Reported net income	174	92	61	150	163
Return on equity (1)	6.6%	3.5%	2.4%	6.3%	7.4%

(1) Adjusted for other comprehensive income.

F2014 Summary

- Manitoba Hydro's earnings increased in F2014 because of increased domestic consumption due to colder temperature and increases in electric rates.
- Extra-provincial revenues also increased as a result of favourable water conditions and higher prices.
- The higher earnings were slightly offset by an increase in fuel and purchased power costs.

F2015 Outlook

- The Utility has forecast lower earnings for F2015 because of a return to more normal winter conditions (compared to F2014) and higher depreciation and interest expenses as a result of the continuing high level of investment in infrastructure. This is expected to be slightly offset by the above-average water storage levels heading into F2015.

The Manitoba Hydro-Electric Board

Report Date:
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Financial Profile

(CA$ millions where applicable)	For the year ended March 31 2014	2013	2012	2011	2010
Cash Receipts from Customers	2,198	2,015	1,998	2,029	2,110
Cash Paid to Suppliers and Employees	(1,070)	(981)	(1,048)	(1,043)	(1,080)
Interest Paid	(510)	(489)	(418)	(422)	(475)
Interest Received	72	44	35	31	34
Cash flow from operations	690	589	567	595	589
Dividends paid	0	0	0	0	0
Capital expenditures	(1,383)	(1,037)	(1,124)	(1,166)	(1,068)
Free cash flow	(693)	(448)	(557)	(571)	(479)
Acquisitions & investments	(89)	(98)	(90)	(88)	(93)
Net sinking fund withdrawals/(payments)	206	22	(75)	527	(274)
Net debt change	707	565	673	192	873
Other	(21)	(59)	29	(164)	(12)
Change in cash	110	(18)	(20)	(104)	15
Total debt (net sinking fund investments)	10,757	9,633	9,010	8,365	7,716
Cash and equivalents	142	32	50	70	174
Total debt in capital structure (1)	79.4%	78.5%	77.9%	77.2%	77.0%
Cash flow/Total debt	6.4%	6.1%	6.3%	7.1%	7.6%
EBIT gross interest coverage (times)	0.95	0.89	0.80	1.00	1.01
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

(1) Adjusted for other comprehensive income.

F2014 Summary

- Credit metrics have declined moderately over the past few years as the substantial amount of capex has led to an increase in debt levels. This trend is expected to continue in the medium term.
- Cash flow from operations increased largely because of higher earnings for the year.
- Capex remained elevated as the Utility spent $904 million in F2014 on new generation and transmission projects.
- The high level of capex resulted in a free cash flow deficit that was mostly funded through advances from the Province.

F2015 Outlook

- Capex is expected to remain elevated over the medium term as construction continues on the Bipole III and the Keeyask Projects.
- This high level of capex is expected to result in a negative free cash flow, which will likely be funded through advances from the Province. The increasing debt load may lead to further declines in Manitoba Hydro's key financial metrics.
- However, with no mandatory dividend payment requirements, this should provide the Utility with some financial flexibility.

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Long-Term Debt Maturities and Bank Lines

Debt Profile (CAD millions)	%	2014	2013	2012
		For the year ended March 31,		
Advances from the Province	97.0%	10,683	9,775	9,095
Manitoba Hydro Bonds	1.6%	169	55	136
Manitoba Hydro-Electric Board Bonds*	1.4%	158	182	194
	100.0%	**11,010**	**10,012**	**9,425**
Adjustments to carrying value of dual currency bonds		(12)	(20)	(24)
Debt discounts and premiums		(96)	22	9
Transaction costs		(34)	(29)	(28)
Total		**10,868**	**9,985**	**9,382**

*Includes $65 million of unguaranteed bonds at March 31, 2014.

Debt Maturities

Year	2015	2016	2017	2018	2019	Thereafter	Total
(CAD millions)	408	313	311	331	1,347	8,300	**11,010**
%	4%	3%	3%	3%	12%	75%	**100%**

Summary

- The Province supports Manitoba Hydro by advancing funds or guaranteeing the Utility's long-term debt issues. Long-term debt at March 31, 2014, consisted of the following:
  - $10,683 million in advances from the Province (all of which have annual sinking fund requirements).
  - $169 million Manitoba Hydro Bonds.
  - $158 million Manitoba Hydro-Electric Board Bonds.
- Only $65 million of Manitoba Hydro-Electric Board Bonds do not carry the provincial guarantee.
- Manitoba Hydro maintains a relatively smooth maturity profile with potential volatility from foreign currency debt mostly mitigated through natural and cash flow hedges, and a moderate level of floating-rate debt (19% of floating-rate debt and 7% of long-term debt to be refinanced within a year), which adds stability to debt servicing costs and minimizes interest rate risk.
- The Utility has bank credit facilities that provide for overdrafts and notes payable of up to $500 million denominated in Canadian and/or U.S. dollars. At March 31, 2014, there were no amounts outstanding. Manitoba Hydro issues short-term promissory notes in its own name for its short-term cash requirements and does not receive short-term funding from the Province. These short-term notes are guaranteed by the Province.

Regulation

Manitoba Hydro is governed by *The Manitoba Hydro Act* and its electricity and natural gas rates are regulated by the Manitoba PUB.

Electricity

- Each year, Manitoba Hydro reviews its financial targets with particular focus on its debt-to-equity target capital structure of 75% to 25%. If the Utility deems a rate adjustment is necessary to continue progress towards attainment of its financial targets, it submits a rate application to the PUB.
- The PUB reviews the rate adjustment application with the objective of allowing Manitoba Hydro to recover its cost of service and achieve its long-term debt-to-equity target. The PUB does not have the mandate to pre-approve capex. The capex planning responsibility resides with Manitoba Hydro and the government of Manitoba.
- In June 2012, Manitoba Hydro filed its 2012–13 and 2013–14 General Rate Application (GRA). In the GRA, the Utility requested an average 2.5% rate increase for all classes, effective September 1, 2012, and an additional 3.5% increase in overall revenues effective April 1, 2013.
- In order 43/13 dated April 26, 2013, the PUB provided final approval of a 3.5% rate increase across the board for all customer classes effective May 1, 2013. The order also provided final approval to the Utility's application to reinstate the 1.0% rate deferral as revenue in the 2012–2013 fiscal year. In addition, the 2.0% interim rate increase granted for April 1, 2012, and the 2.4% interim rate increase granted for September 1, 2012, were also approved.
- The Utility submitted an application for interim rates effective April 1, 2014, in March 2014. On May 6, 2014, the PUB approved a 2.75% increase in interim rates effective May 1, 2014.
- While Manitoba Hydro is the sole retail electricity supplier in Manitoba, under *The Manitoba Hydro Amendment Act* (the Act), other utilities may access the transmission system to reach customers in neighbouring provinces and states.
- The Act also explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures and to create subsidiaries.
- There are presently no plans to move to full retail competition in the province.
- Manitoba retail customers currently enjoy rates that are among the lowest in North America as a result of Manitoba Hydro's predominantly hydroelectric generation and efficient resource management.

Natural Gas Distribution

- Manitoba Hydro distributes natural gas through its wholly owned subsidiary, Centra Gas Manitoba Inc. (Centra Gas). In accordance with the rate-setting methodology for natural gas, commodity rates are changed every quarter based on 12-month forward natural gas market prices.
- The commodity cost of gas is a pass-through with no markup to customers.
- Non-commodity costs, such as transportation, distribution as well as operating and general expenses related to the natural gas business are also passed on.
- The PUB allows Centra Gas to target an annual profit of approximately $3 million, which is fairly modest compared with Manitoba Hydro's consolidated earnings.
- On July 26, 2013, the PUB issued order 85/13, which approved an approximate 1% general revenue increase for gas operations, effective August 1, 2013.

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Watershed Storage Capacity

Manitoba Hydro draws water from five distinct watersheds: Nelson River, Winnipeg River, Saskatchewan River, Churchill River (including the Laurie River) and Burntwood River. This provides the Utility with some geographic diversification, especially during times of low hydrology. The main generation source is the Nelson River, which accounted for approximately 74% of power generated in F2014.

SOURCE OF ELECTRICAL ENERGY GENERATED AND IMPORTED

For the year ended March 31, 2014

Nelson River	**73.63%**	**Saskatchewan River**	**6.69%**
Billion kWh generated	**27.1**	**Billion kWh generated**	**2.5**
Limestone	23.89%	Grand Rapids	6.69%
Kettle	23.03%		
Long Spruce	19.23%	**Laurie River**	**0.08%**
Kelsey	5.82%	**Billion kWh generated**	**0.0**
Jenpeg	1.66%	Laurie River #1	0.04%
		Laurie River #2	0.04%
Winnipeg River	**10.95%**		
Billion kWh generated	**4.0**	**Burntwood River**	**4.03%**
Seven Sisters	3.15%	**Billion kWh generated**	**1.5**
Great Falls	2.76%	Wuskwatim	4.03%
Pine Falls	1.59%		
Pointe du Bois	1.01%		
Slave Falls	1.23%		
McArthur	1.21%		
Thermal	**0.35%**	**Purchases (excl. wind)**	**1.74%**
Billion kWh generated	**0.1**	**Billion kWh imported**	**0.6**
Brandon	0.32%		
Selkirk	0.04%	**Wind**	**2.52%**
		Billion kWh imported	**0.9**

Source: Manitoba Hydro.

Favourable characteristics inherent in Manitoba Hydro's watersheds include the following:

- Cold temperatures reduce overall evaporation rates as much of the water is frozen for up to five months of the year.
- A significant portion of the watersheds consists of rock, which has lower seepage rates and higher runoff than predominantly soil-covered watersheds.
- Lake Winnipeg, Cedar Lake and Southern Indian Lake serve as large storage reservoirs. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices and selling its electricity during peak demand periods at higher prices).

In addition to its own generating stations in Manitoba, Manitoba Hydro purchases all electricity from two wind farms in southern Manitoba in St. Joseph and St. Leon. The installed capacity of these facilities is 258.5 MW. The Wuskwatim generation station is owned by the Wuskwatim Power Limited Partnership, in which Manitoba Hydro is the majority owner. Manitoba Hydro purchases all the electricity generated from the Wuskwatim generating station.

DBRS

The Manitoba Hydro-Electric Board

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Generating Capacity

Manitoba Hydro owns and operates an aggregate generating capacity of 5,725 MW.

Manitoba Hydro's Generating Stations and Capabilities

For the year ended March 31, 2014			**Net Capacity**
Power Station	**Location**	**# of units**	**(MW)**
Hydroelectric			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	87
McArthur Falls	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	67
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	292
Kettle	Nelson River	12	1,220
Jenpeg	Nelson River	6	125
Long Spruce	Nelson River	10	980
Limestone	Nelson River	10	1,350
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	214
Total Hydroelectric Generation		**105**	**5,248**
Thermal			
Brandon (coal: 98 MW, gas: 244 MW)		3	342
Selkirk (gas)		2	125
Total Thermal Generation		**5**	**467**
Isolated Diesel Capabilities			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
Total Isolated Diesel Generation			**10**
Total Generation Capacity			**5,725**

Source: Manitoba Hydro.

The Manitoba Hydro-Electric Board

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The Manitoba Hydro-Electric Board

(CA$ millions)	Mar. 31 2014	Mar. 31 2013	Mar. 31 2012		Mar. 31 2014	Mar. 31 2013	Mar. 31 2012
Assets				**Liabilities & Equity**			
Cash & equivalents	142	32	50	S.T. borrowings	0	0	0
Accounts receivable	520	421	328	Accounts payable	561	397	308
Inventories	81	93	106	Current portion L.T.D.	408	656	281
Prepaid expenses & other	0	4	4	Other current liab.	100	103	157
Total Current Assets	743	550	488	**Total Current Liab.**	1,069	1,156	746
Net fixed assets	13,627	12,508	11,797	Long-term debt (net sinking fund investments)	10,349	8,977	8,729
Goodwill & intangibles	281	276	268	Sinking fund investments	111	352	372
Investments & others	988	1,208	1,238	Other L.T. liab.	1,225	1,121	1,067
				Shareholders' equity	2,885	2,936	2,877
Total Assets	15,639	14,542	13,791	**Total Liab. & SE**	15,639	14,542	13,791

Balance Sheet & Liquidity & Capital Ratios	**2014**	**2013**	**2012**	**2011**	**2010**
	For the year ended March 31				
Current ratio	0.70	0.48	0.65	1.22	0.88
Total debt in capital structure	78.9%	76.6%	75.8%	74.6%	74.9%
Total debt in capital structure (1)	79.4%	78.5%	77.9%	77.2%	77.0%
Cash flow/Total debt	6.4%	6.1%	6.3%	7.1%	7.6%
(Cash flow-dividends)/Capex	0.50	0.57	0.50	0.51	0.55
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)					
EBIT gross interest coverage	0.95	0.89	0.80	1.00	1.01
EBITDA gross interest coverage	1.63	1.56	1.43	1.69	1.68
Fixed-charge coverage	0.95	0.89	0.80	1.00	1.01
Profitability Ratios					
Purchased power/Electricty revenues	9.4%	7.7%	9.3%	6.6%	6.6%
Operating margin	30.5%	30.2%	28.4%	32.7%	33.3%
Net margin	8.7%	4.9%	3.6%	8.5%	9.5%
Return on equity (1)	6.6%	3.5%	2.4%	6.3%	7.4%

(1) Adjusted for other comprehensive income.

The Manitoba Hydro-Electric Board

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Ratings

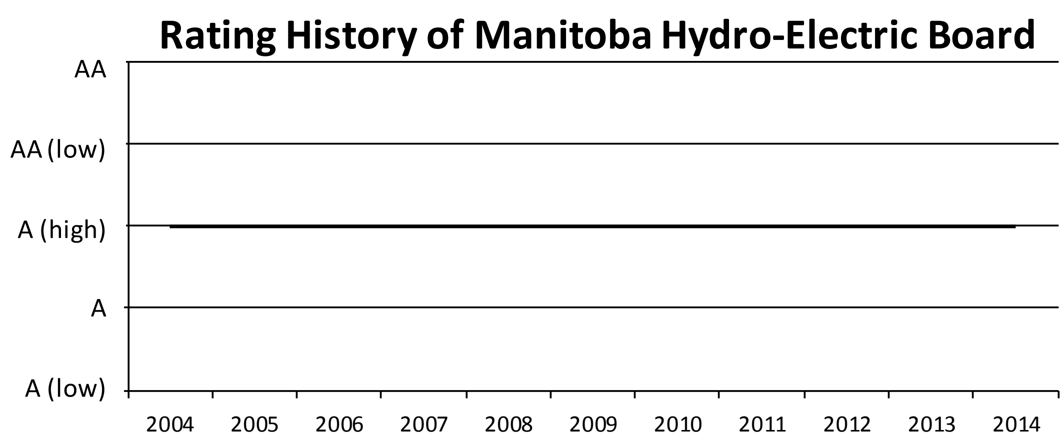
Debt	Rating	Rating Action	Trend
Long-Term Obligations	A (high)	Confirmed	Stable
Short-Term Obligations	R-1 (middle)	Confirmed	Stable

Note: These Obligations are based on the status of Manitoba Hydro as a Crown agent of the Province and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

Rating History

	Current	2013	2012	2011	2010	2009
Long-Term Obligations	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Obligations	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Note: These Obligations are based on the status of Manitoba Hydro as a Crown agent of the Province and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.



Note:
All figures are in Canadian dollars unless otherwise noted.

MOODY'S
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CREDIT ANALYSIS

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This Credit Analysis provides an in-depth discussion of credit rating(s) for Manitoba, Province of and should be read in conjunction with Moody's most recent Credit Opinion and rating information available on Moody's website.

Manitoba, Province of

Canada

Ratings

Manitoba, Province of

Category	Moody's Rating
Outlook	Negative
Senior unsecured bonds	Aa1

Overview and Outlook

Manitoba's Aa1 senior unsecured debt ratings benefit from (1) the diversity and stability of its economy; (2) the province's high degree of financial flexibility as evidenced by access to a broad and stable tax base; (3) manageable refinancing needs and exceptional access to capital markets; (4) high debt affordability as well as (5) adequate, though declining level of liquidity.

The rating is constrained by the province's high debt burden, which we expect to reach about 150% of revenues in 2016-17, versus 144% in 2013-14. Manitoba's deficits are small relative to other provinces and Manitoba enjoys financial flexibility. However, its plan to return to a small surplus by 2016-17 relies to a substantial degree on the province's ability to contain expenditure growth, which we view as challenging.

The negative rating outlook reflects our assessment of the execution risk surrounding Manitoba's plan to achieve a balanced budget by fiscal year 2016-17 and the risk of a continued increase in debt beyond 2016-17.

The outlook could be stabilized if Manitoba's debt burden as a percentage of revenues stabilizes and the province is on track to achieve a return to balanced budgets by 2016-17.

A loss of fiscal discipline leading to a continued and sustained increase in debt and debt service ratios beyond projections could exert downward pressure on the rating. This would be evidenced by reduced likelihood that Manitoba can return to balanced budgets by 2016-17 and reduced commitment to stabilize its debt burden in the medium term.

This Credit Analysis elaborates on Manitoba's profile in terms of the main analytic factors in Moody's Regional and Local Government Methodology.

Baseline Credit Assessment

Financial Performance and Debt Profile

Deficits are small but maintaining a tight grip on expenditures will be challenging

Manitoba's deficits are small and the province budgets for a deficit of 2.4% of total revenues (C$357 million) in 2014-15, which follows a deficit of 3.7% (C$522 million) in 2013-14. The province confirmed its deficit target for 2014-15 with the release of Q1 2014-15. However, we caution that the net financial impact of the recent flooding in summer has not yet been determined which might require some additional unbudgeted expenditures.

Manitoba seeks to return to balanced budgets by 2016-17. We view the province's target as challenging given continued pressures on healthcare (39% of total expenditures, 4.6% annual growth in 2013-14)) and education (24% of total expenditures, 6.7% annual growth in 2013-14) , similar to other provinces, and modest GDP growth. From 2014-15 to 2017-18 revenues are forecasted to grow on average by 3.3% per year including the impact of stable federal transfers while expenditures are expected to grow by only 1.9% during the same period. Manitoba has a solid track record of realizing efficiency gains and controlling departmental expenses providing some comfort that Manitoba can achieve its spending targets. However, we also note that the 2013-14 deficit of C$522 million was C$90 million higher than preliminary figures published as part of the 2014-15 budget earlier this year, after including a settlement provision for costs associated with effects of long standing flooding issues in four First Nations communities. In addition, total expenditures grew by 4.0% in 2013-14 after a year of tight expenditure control in 2012-13.

The province has substantial financial flexibility to raise taxes; however, willingness to raise taxes or constrain growth in provincial services may be limited by a modest economic growth environment and competition for skilled labour force from lower tax jurisdiction such as Alberta.

Stabilization of high debt burden

Manitoba's current debt burden is high. We expect that debt accumulation will continue to slightly outpace annual revenue growth as a result of small budgeted deficits until 2016-17 and capital spending under its 5-year C$5.5 billion infrastructure plan. We anticipate net debt to revenues to stabilize at around 150% by 2016-17 which compares to 144% in 2013-14 and 101% in 2008-09. Net direct and indirect debt should remain stable as a percentage of GDP (around 30%).

Unfunded pension liabilities of around 18% of revenues at March 31, 2014 remain manageable. In 2007-08, the province debt-financed C$1.5 billion of the Teachers' Retirement Allowance Fund (TRAF) unfunded liability. Investments held for the TRAF and the Civil Service Superannuation Fund (CSSF), which totaled C$2.2 billion in 2007-08, were reclassified and irrevocably restricted for pension purposes in 2008-09.

Continued high debt affordability

Over the last few years, Manitoba has rolled over maturing debt into debt with longer maturities and at comparatively low interest rates. Despite higher absolute debt levels, interest costs have consumed approximately 6% of revenues over the last five years, half of the comparable level in 2001. We expect interest burden to remain at current levels over the next 2-3 years even if interest rates were to rise modestly and assuming a moderate increase in debt. Manitoba faces refinancing needs of approximately C$2.0-2.5 billion every year from 2015-16, which is manageable.

Adequate, though declining level of liquidity funds

Manitoba's liquidity cushion is adequate with about C$2.6 billion in cash and investments (excluding sinking funds). Cash and investments are relatively low compared to expenditures (17% in 2013-14) and to debt (13% in 2013-14), which is also a reflection of the exceptional capital market access of Canadian provinces.

Cash and investments include approximately C$275 million of liquid funds in its Fiscal Stabilization Account. The province will draw C$55 million from the Fiscal Stabilization Account in 2014-15 for debt repayment. The fund is now well below its peak of C$864 million in 2008-09 and has limited cushion to absorb future drawings.

Inherent risks related to increasing debt at self-supporting entity Manitoba Hydro

The province issues debt on behalf of its wholly-owned utility company Manitoba Hydro, which we view as a self-supporting entity and therefore, exclude the related net debt from the Province of Manitoba's debt metrics. Manitoba Hydro's total reported debt net of sinking funds was around C$11.0 billion at March 31, 2014.The anticipated increase in debt at Manitoba Hydro could increase the contingent liability for the province of Manitoba in the next few years.

In anticipation of demand increases by 2022-23, and in order to boost electricity exports, Manitoba Hydro is currently executing major generation and transmission projects. Manitoba's financial metrics will be strained by the associated capital expenditures and debt needs in the coming years. In 2014-15, C$1.5 billion of C$2.4 billion in new debt that Manitoba seeks to issue will be for Manitoba Hydro. In addition, the management of these lengthy and complex construction projects will require additional attention from management. We will monitor the increase in Manitoba Hydro's debt ratios and the progress of construction of these projects.

We note positively, that Manitoba Hydro has flexibility to increase utility rates given fairly low rates compared to other provinces and that it has already negotiated future long-term export contracts with customers in the US. Please see the Credit Opinion for Manitoba Hydro for further details.

Governance and Management Factors

Manitoba relies on multi-year fiscal planning and prudent economic and fiscal assumptions to maintain a strong financial profile. Overall, Manitoba displays strong governance and management factors. Fiscal management measures are supported by comprehensive and transparent financial reporting that is typical of governments in advanced industrial economies.

Economic Fundamentals

Manitoba's economy is characterized by a high degree of diversification which provides access to a broad and productive tax base and supports economic stability. Approximately 11 sectors represent more than 5% of provincial GDP and manufacturing remains the largest sector (10% of provincial GDP). Manitoba's economy tends to perform approximately in line with the Canadian average and real GDP grew by an average 1.8% over the period 2008-13 compared to a Canadian average of 1.4%.

For 2014, real GDP growth is expected to be around 2.1%, benefiting from a pick-up in manufacturing and mining, while the agricultural sector is expected to decline following an exceptionally strong 2013. Manitoba's unemployment rate is among the lowest in Canada (5.4% in Manitoba, 7.1% in Canada in 2013) and its population has low household debt relative to other Canadian provinces.

Manitoba's economy has been hit by an increased frequency of major flooding in recent years and the province is stepping up investments in flood protection infrastructure, financed partially by a 1% increase in the provincial sales tax (PST) to 8%.

Institutional Framework

The institutional framework governing relations, powers and responsibilities between the Canadian provinces and the federal government is well developed and stable. This framework provides provinces with unfettered access to a broad range of tax bases and wide discretion over expenditure decisions, allowing provinces substantial flexibility to address fiscal challenges. Compared to their counterparts in other countries, including the German Länder and the Australian states, Canadian provinces enjoy far greater autonomy in terms of both the expenditure and revenue sides of their budgets. As such, Canadian provinces benefit from a high degree of fiscal policy flexibility that is more akin to that of sovereign governments than to many of their international sub-sovereign peers. These positive institutional factors increase Canadian provinces' ability to manage through economic downturns and handle relatively high debt burdens.

Extraordinary Support Considerations

Moody's assigns a high likelihood of extraordinary support from the Government of Canada (Aaa, stable), reflecting Moody's assessment of the incentive provided to the federal government of minimizing the risk of potential disruptions to capital markets if Manitoba, or any province, were to default. It also indicates a moderately positive federal government policy stance as illustrated by the flexibility inherent in the system of federal-provincial transfers.

National Peer Comparison

The Province of Manitoba is rated in the mid-range of Canadian provinces, whose ratings remain in a narrow range of Aaa to Aa2. Manitoba's debt burden is higher than that of some of its Western Canadian peers, but remains around the Canadian median. The province's highly diversified economy and resulting economic stability positions the province adequately relative to lower rated Canadian peers.

Rating History

Manitoba, Province of

Date	Rating
November 2006	Aa1
January 2003	Aa2
September 1998	Aa3
May 1985	A1
September 1975	Aa
October 1968	A

Source: Moody's Investors Service.

Annual Statistics

Manitoba, Province of

	2010	2011	2012	2013	2014	2015F
Debt Statement (C$ millions, as at 3/31)						
Treasury Bills and Promissory Notes	1,500	1,250	1,435	1,925	1,675	1,625
Canada Pension Plan	480	492	492	492	492	492
Direct Debentures	22,336	23,751	26,558	27,840	30,058	32,580
Other	785	780	812	815	910	864
Total Direct Debt	**25,101**	**26,273**	**29,297**	**31,072**	**33,135**	**35,561**
Guaranteed Debt						
Manitoba HydroBonds and Promissory Notes	251	163	254	163	263	243
Other Guarantees	102	100	104	96	96	96
Total Direct and Indirect Debt	**25,454**	**26,536**	**29,655**	**31,331**	**33,494**	**35,900**
Less:						
Manitoba Hydro	8,288	8,467	9,095	9,775	10,683	12,267
Manitoba HydroBonds and Promissory Notes	251	163	254	163	263	243
Direct Debt Sinking Fund	2,592	2,458	2,335	2,159	2,059	2,095
Net Direct and Indirect Debt	**14,323**	**15,448**	**17,971**	**19,234**	**20,489**	**21,295**

Note: 2015F based on 2014-15 budget and Moody's estimates.

Debt Trends (as at 3/31)						
Net Direct and Indirect Debt (C$ millions)	**14,323**	**15,448**	**17,971**	**19,234**	**20,489**	**21,295**
As % GDP	28.3	29.2	32.6	33.0	33.9	34.1
Per Capita (C$)	11,851	12,653	14,566	15,381	16,192	16,610
As % Total Revenues	113.2	116.7	131.3	141.3	144.1	145.6
Total Direct and Indirect Debt	**25,454**	**26,536**	**29,655**	**31,331**	**33,494**	**35,900**
% Hydro Debt	32.6	31.9	30.7	31.2	31.9	34.2
Total Foreign Currency Debt (Before Hedges)	**6,194**	**6,172**	**6,887**	**8,443**	**8,034**	
As % Total Direct and Indirect Debt	24.3	23.3	23.2	26.9	24.0	
Foreign Currency Debt Net of Hedges (C$ Millions)	**2,426**	**1,884**	**2,037**	**2,071**	**1,888**	
As % Total Direct and Indirect Debt	9.5	7.1	6.9	6.6	5.6	
Short-Term Debt	**3,464**	**3,349**	**3,681**	**4,401**	**4,217**	**2,054**
As % of Total Direct and Indirect Debt	13.6	12.6	12.4	14.0	12.6	5.7
Actuarial Pension Liability (Surplus) (C$ millions)	**1,800**	**1,731**	**1,634**	**1,828**	**2,038**	**2,261**
As % of GDP	3.6	3.3	3.0	3.1	3.4	3.6
As % of Revenue	14.2	13.1	11.9	13.4	14.3	15.5
Total Employer Cash Contributions [1]	**510**	**358**	**425**	**207**	**239**	**-**
As % of Revenue	**4.0**	**2.7**	**3.1**	**1.5**	**1.7**	**-**

Note: 2015F based on 2014-15 budget and Moody's estimates.

Manitoba, Province of

	2010	2011	2012	2013	2014	2015F
Consolidated Revenues and Expenses (C$ millions, Year Ending 3/31)						
Revenues						
Personal Income Tax	2,402	2,592	2,697	2,846	2,978	3,102
Corporate Income Tax	257	330	441	456	468	530
Payroll Tax (Health and Education)	264	269	292	296	315	326
Retail Sales Tax	1,570	1,618	1,658	1,767	2,028	2,207
Other taxes	1,447	1,519	1,400	1,302	1,380	1,700
Net Income of Government Business Enterprises	772	807	713	739	783	692
Federal Transfers	3,924	4,047	4,332	3,953	3,842	3,793
Other	2,012	2,058	2,155	2,255	2,420	2,281
Total Revenues	**12,648**	**13,240**	**13,688**	**13,614**	**14,214**	**14,630**
Expenses						
Health	4,831	5,044	5,328	5,454	5,706	5,791
Family Services and Housing	1,295	978	1,013	1,035	1,074	1,115
Education	3,227	3,330	3,389	3,339	3,562	3,895
Community, Economic and Resource Development	1,813	2,400	2,734	2,423	2,415	2,477
Debt Service	756	773	815	839	821	872
Other	926	894	1,410	1,084	1,158	837
Total Expenses	**12,848**	**13,419**	**14,689**	**14,174**	**14,736**	**14,987**
Consolidated Surplus/(Deficit)	**(200)**	**(179)**	**(1001)**	**(560)**	**(522)**	**(357)**
Cash Financing Surplus/(Requirement)	**(1413)**	**(1192)**	**(1935)**	**(1323)**	**(963)**	**(1330)**

Note: 2015F based on 2014-15 budget and Moody's estimates.

Financial Trends (Year Ending 3/31)						
% Change in Revenue	(0.9)	4.7	3.4	(0.5)	4.4	2.9
As a % of Revenue						
Consolidated Surplus (Deficit)	(1.6)	(1.4)	(7.3)	(4.1)	(3.7)	(2.4)
Cash Financing Surplus (Requirement)	(11.2)	(9.0)	(14.1)	(9.7)	(6.8)	(9.1)
Interest Expense	6.0	5.8	6.0	6.2	5.8	6.0
Intergovernmental Transfers	31.0	30.6	31.6	29.0	27.0	25.9
% Change in Expenses	4.4	4.4	9.5	(3.5)	4.0	1.7
As a % of Expenses						
Health	37.6	37.6	36.3	38.5	38.7	38.6
Education	25.1	24.8	23.1	23.6	24.2	26.0
Interest Expense	5.9	5.8	5.5	5.9	5.6	5.8
As a % of GDP						
Revenues	25.0	25.0	24.8	23.4	23.5	23.4
Expenses	25.4	25.4	26.6	24.3	24.4	24.0
Consolidated Surplus (Deficit)	(0.4)	(0.3)	(1.8)	(1.0)	(0.9)	(0.6)
Cash Financing Surplus (Requirement)	(2.8)	(2.3)	(3.5)	(2.3)	(1.6)	(2.1)
Health Expenses	9.5	9.5	9.7	9.4	9.4	9.3
Expenses Per Capita (C$)	10,631	10,991	11,906	11,335	11,645	11,690

Note: 2015F based on 2014-15 budget and Moody's estimates.

Manitoba, Province of

	2009	2010	2011	2012	2013	2014F
Economic Trends (Year Ending 12/31)[1]						
Population in 1000s	1,209	1,221	1,234	1,250	1,265	1,282
Real GDP (2007 2002 C$ millions)	51,048	52,379	53,269	54,633	55,944	57,119
% Growth	-0.2	2.6	1.7	2.6	2.4	2.1
Nominal GDP (C$ millions)	50,636	52,896	55,169	58,245	60,400	62,514
% Growth	-2.5	4.5	4.3	5.6	3.7	3.5
Employment Growth	0.0	1.9	0.8	0.9	0.5	1.0
Participation Rate	69.1	69.6	69.3	69.1	68.7	
Unemployment Rate	5.2	5.4	5.4	5.3	5.4	5.2
Manufacturing Shipments (C$ millions)	14,669	14,367	15,229	15,398	15,428	-
Housing Starts (units)	4,174	5,888	6,083	7,242	7,465	-
Retail Sales (C$ millions	14,920	15,770	16,443	16,652	17,297	
Per Capita (C$)	12,345	12,917	13,328	13,317	13,669	
CPI, All Items	114.1	115.0	118.4	120.3	123.0	125.2
Inflation Based on CPI % Change	0.6	0.8	3.0	1.6	2.2	1.8

Note: 2014 F are forecasted figures and not based on audited financial accounts. Sources for historical years: Statistics Canada, Manitoba.

Moody's Related Research

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» Canadian Provinces: Challenges Continue as Seven Forecast Budget Deficits, May 2014 (170924)

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Credit Opinion: Manitoba Hydro Electric Board

Global Credit Research - 06 Nov 2014

Manitoba, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Commercial Paper	P-1
Parent: Manitoba, Province of	
Outlook	Negative
Senior Unsecured	Aa1

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Opinion

Rating Drivers

Manitoba Hydro-Electric Board's (Manitoba Hydro) commercial paper program is explicitly guaranteed by the Province of Manitoba (Province).

Corporate Profile

Manitoba Hydro is an integrated electric and gas utility that is wholly owned by the Province as a Crown corporation and is regulated by the Manitoba Public Utilities Board (MPUB). Manitoba Hydro's 5,725 MW installed generating capacity produces over 90% of its electricity via hydroelectric power, complemented by two thermal and four diesel facilities, as well as power purchased from two independent wind farms. More than 20% of Manitoba Hydro's FY2014 electric revenue comes from exports to three Midwest US wholesale markets and other Canadian provinces. The smaller natural gas distribution segment, which sources its gas from Alberta, accounts for 8% of FY2014's total revenue net of procurement cost. Manitoba Hydro serves 555,760 electric and 272,228 gas customers in the Province.

SUMMARY RATING RATIONALE

Manitoba Hydro's Prime-1 commercial paper rating is driven by the Province's senior unsecured rating (Aa1/NEG) as the Province explicitly guarantees its commercial paper program. The commentary provided in the detailed rating considerations evaluates Manitoba Hydro as an electric utility corporation without layering in the guarantee. The commentary is provided solely for the benefit of investors as a reference as Manitoba Hydro's Prime-1 rating is determined by the Province's credit rating.

DETAILED RATING CONSIDERATIONS

OWNERSHIP BY THE PROVINCE OF MANITOBA

We view the Province's ownership of Manitoba Hydro as the anchor that links Manitoba Hydro's credit quality closely to that of the Province's. At FYE2014 , $10.7 billion of the $11 billion total debt consists of long term debt advances from the Province. Of debt obligations not owed to the Province, the Province guarantees Manitoba Hydro's short-term promissory note program (i.e. commercial paper program or CP) and its other long term debt (with the exception of Manitoba Hydro-Electric Board Bonds issued for mitigation purposes, which stood at $65 million at FYE2014). In turn, Manitoba Hydro is required to make sinking fund payments each year for no less than 1% of preceding fiscal year's principal debt outstanding and 4% of preceding fiscal year's sinking fund balance. In addition, the Provincial Debt Guarantee Fee is calculated as 1% of total guaranteed debt outstanding. Moody's continues to expect Manitoba Hydro to operate as a self-sufficient corporation to service its debt and afford payments to the Province such as water rentals and assessments.

LOW RATES IN A STABLE REGULATORY AND ECONOMIC ENVIRONMENT

Manitoba Hydro operates in a stable regulatory framework with steady yearly rate increases. It forecasts annual rate increases of 3.95% until FY2033 to contribute to replacing aging generation, transmission and distribution facilities. The rates are set on a cost-of-service basis. The MPUB independently oversees the rate setting process and has a supportive environment for cost recovery. Residents in Manitoba continue to pay rates that are among the lowest in North America. Revenues from exports to the US and other Canadian provinces accounts for over 20% of electric revenue, alleviating pressure of rate hikes and contributing to the current low rates in the Province.

NEW CAPACITY PLANNED TO MEET DEMAND AND BOOST EXPORT

To enhance reliability and in anticipation of demand growth and new generation needs in the next decade, major generation and transmission projects are underway. The 695 MW Keeyask Generating Station estimated at $6.5 billion is currently under construction with a projected in-service of 2019. Also under construction is the $4.6 billion Bipole III transmission line expansion with a projected in-service of 2018. As a result, capital expenditures are projected to increase and peak in FY2017.

The new capacity will be partially underpinned by fixed price long-term export contracts. Generation capacity from new hydro stations is developed in large "blocks" while demand grows incrementally. This creates an opportunity to sell surplus firm power under long-term contracts. Manitoba Hydro has already entered into long term contracts aggregating over 1,800 MW with Northern States Power, Minnesota Power, Wisconsin Public Service and Great River Energy. The contracts, which set electricity prices at a negotiated, fixed price remain subject to regulatory approval and are conditional upon the successful construction of the proposed plants.

In June 2014, the MPUB completed the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's preferred development plan. In July 2014, the Keeyask project received its environmental license from the Province and construction started. The planning of the Conawapa Generating Station was suspended in August 2014 and whether it will be reactivated in the future is dependent upon further evaluation through the Integrated Resource Planning process and whether a strong investment case can be made.

FINANCIAL TARGETS TO BE CHALLENGED BY HIGHER CAPEX

As part of its debt management strategy, Manitoba Hydro targets certain financial metrics such as an interest coverage ratio greater than 1.2 and equity-to-capitalization greater than 25%. However, both targets are not expected to be met for an extended period of time due to large generation and transmission projects underway such as Keeyask and Bipole III. Total capital expenditures are forecasted to be $13 billion, or on average $2.6 billion per year from FY2015 to FY2019.

The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays given the nature of a hydroelectric plant's long construction cycle prior to the start of operations and cash flow. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation.

Liquidity Profile

Manitoba Hydro's commercial paper is unconditionally guaranteed as to the principal and interest by the Province of Manitoba. Under the Manitoba Hydro Act, Manitoba Hydro can issue up to $500 million of commercial paper. While the Province does not maintain committed bank credit facilities in support of its short-term borrowing programs, Moody's believes that the probability that the Aa1-rated Province would be unable to obtain funding on a timely basis either from the capital markets or from its bankers is highly remote.

Rating Outlook

The outlook of Manitoba Hydro is stable, reflecting our expectation that the Province of Manitoba will continue to be the unconditional guarantor of Manitoba Hydro's commercial paper program. Manitoba Hydro is rated Prime-1 based on Moody's Global Short-Term Rating scale. The rating on the province would have to be downgraded 5 notches to A3 before we would downgrade Manitoba Hydro's Prime-1 rating to Prime-2.

What Could Change the Rating - Up

The Prime-1 rating is the highest short-term rating Moody's can assign and is indicative of a superior ability to repay short-term debt obligations. Therefore, Manitoba Hydro's Prime-1 rating cannot have any upward revision.

What Could Change the Rating - Down

Manitoba Hydro's Prime-1 rating is determined by the Province's long-term rating. Manitoba Hydro's Prime-1 rating could be revised downward to Prime-2 should the Province fail to maintain its long-term rating above A3.

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MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

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Appendices

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

CAPITAL EXPENDITURE FORECAST

4.0 OVERVIEW

Tab 4 summarizes the Capital Expenditure Forecast (CEF14) and the capital investments required to meet the growing energy needs of Manitoba and to replace aging utility assets.

Sections 4.1 and 4.2 discuss Manitoba Hydro's Capital Expenditure forecast for Electric Operations (CEF14). Section 4.3 provides an overview of major new generation and transmission capital expenditures. Section 4.4 provides an overview of sustaining capital expenditure requirements. Section 4.5 summarizes the assets that are projected to enter into service. Section 4.6 provides more detailed information with respect to the condition of Manitoba Hydro's assets and future sustaining capital requirements.

The key conclusions with respect to Tab 4 are:

1. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade with the condition of the Corporation's assets more and more contributing to the decline in reliability.

2. Manitoba Hydro is entering a period of extensive capital investment to meet the growing energy requirements of Manitoba, to replace aging utility assets and address increased capacity needs on the system.

3. Manitoba Hydro's projected costs and revenue requirements are significantly increasing due to the investment in assets and are the key factors driving the need for rate increases.

4. The proposed 3.95% rate increases are the minimum required to continue to deliver a reliable energy supply to Manitobans, to which they are accustomed, and fund Power Smart Programs to assist customers in meeting their energy needs.

5. The key reliability risks associated with inadequate funding as a result of rate increases lower than 3.95% include:
   i. Reliability would degrade further; outages would be longer and more frequent;
   ii. Increased safety risks to public and staff; and
   iii. Increased maintenance and emergency costs.

4.1 CAPITAL EXPENDITURE FORECAST

The Capital Expenditure Forecast is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the Province. Expenditures included in the CEF provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner. A copy of CEF14 is included as Appendix 4.1.

The CEF for the current year and subsequent nineteen year period is submitted annually to the MHEB for approval. Since capital construction projects typically span several years, each year's CEF is presented to the MHEB as a revision to the previous year's approved CEF. In addition to the identification of new projects, changes to previously approved projects are also identified.

Business Units' initiate capital expenditure proposals to meet energy load growth demands within the Province, to respond to specific customer service extension requirements, to improve the efficiency and reliability of the energy delivery system or to take advantage of revenue generating opportunities in the export market. Once the need for a capital project is identified, a Capital Project Justification (CPJ) is prepared by the initiating department. The CPJ contains detailed information relative to each project such as system load growth statistics, business case analysis, risk assessment, and other pertinent details. The requirement and justification for the project is reviewed at the department, division and business unit level before the CPJ is forwarded to either the responsible Vice-President or the Executive Committee of Manitoba Hydro for approval. Projects greater than $50 million require approval of the Executive Committee, items below $50 million are approved at the Business Unit level. Depending on the nature and complexity of the project, the CPJ may also be advanced to Manitoba Hydro's Planning Review Committee.

CPJs are scrutinized to confirm the need for the project based on the following criteria: system reliability, safety, efficiency, customer service, environmental impacts and corporate profitability. Further consideration is given to the priority of proposed projects and whether projects of lesser priority can be displaced so overall funding levels remain within the MHEB approved CEF limits. Risks of not proceeding with the project are also assessed based on information provided within the CPJ. All projects are assessed for environmental impacts.

During the year, actual expenditures on projects are reported monthly to Business Unit Management and the Executive Committee. Variance explanations are provided for any significant variances from the approved CEF. This information is also reported to the MHEB at their regularly scheduled meetings.

Each Vice-President oversees the portfolio of capital projects within their approved target. Advancement and deferral of capital projects occurs throughout the year to manage within annual approved funding levels. Available capital is allocated to asset categories in a prioritized manner to mitigate overall operational and financial risk.

4.2 ELECTRIC OPERATIONS CAPITAL EXPENDITURE FORECAST (CEF14)

The CEF includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability and a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major and base items together comprise sustaining capital.

Figure 4.1 below provides a breakdown of Major New Generation and Transmission and sustaining capital by Business Unit over the 2014/15 to 2016/17 timeframe and the 10 year forecast period.

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Major New Generation & Transmission	**1 452**	**1 914**	**2 463**	**11 671**
Sustaining Capital (Major & Base)	**571**	**577**	**610**	**5 661**
Generation Operations	132	132	132	1 336
Transmission	125	125	125	1 350
Customer Service & Distribution	236	241	268	2 212
Customer Care & Marketing	3	4	4	39
Human Resources & Corporate Services	75	75	55	597
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Total Electric	**2 023**	**2 491**	**3 073**	**17 332**

Figure 4.2 below illustrates projected capital expenditures by major category to 2023/24.

Figure 4.2 Capital Expenditure Forecast- Electric Operations

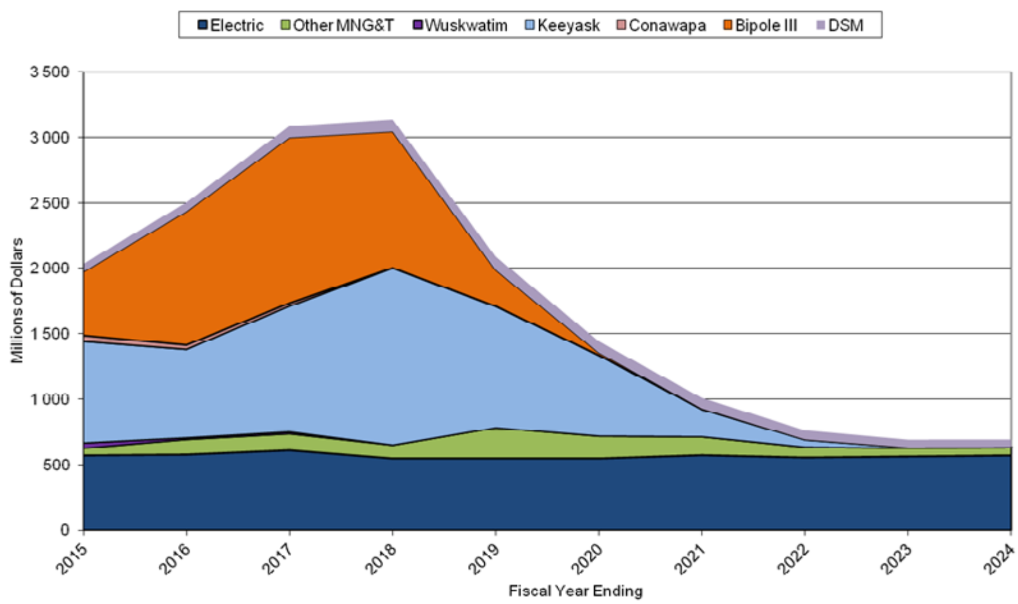


Figure 4.3 provides a summary of CEF14, related to Electric operations, and shows a reduction of $3.5 billion for the 10 year period to 2023/24 as compared to CEF13.

Figure 4.3 Change in Cost Flow from CEF13 to CEF14 ($ millions)

Electric Only	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	**2 013**	**2 422**	**2 496**	**2 326**	**2 030**	**1 845**	**1 337**	**1 719**	**2 281**	**2 322**	**20 792**
Incr (Decr)	9	69	577	799	48	(414)	(339)	(968)	(1 601)	(1 641)	(3 460)
CEF14	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**	**17 332**

The decrease of $3,460 million in capital expenditures over the ten year forecast period is comprised of the following:

Figure 4.4 Breakdown of CEF14 10 Year Cost Flow Change

	Total Projected Cost	**10 Year Increase (Decrease)**
		($ Millions
Conawapa - Generation	397	(6 052)
Bipole III - Transmission Line	1 655	407
Bipole III - Converter Stations	2 675	881
Bipole III - Collector Lines	260	71
Keeyask - Generation	6 496	349
Demand Side Management	NA	463
Base Capital Target	NA	422
Additional North South Trasmission	-	(90)
Gillam Redevelopment and Expansion Program	266	(77)
Dorsey 230KV Zone Building	-	(63)
Slave Falls Major Overhauls	126	(63)
Pointe du Bois Powerhouse Rebuild	1 852	(19)
New Adelaide Station - 66/12kV	62	62
Other System Upgrades		249
		(3 460)

4.3 MAJOR NEW GENERATION & TRANSMISSION CAPITAL EXPENDITURES

The CEF14 includes Major New Generation & Transmission projects which significantly increase capacity and energy or provide increased reliability for the transmission system.

As noted in Figure 4.5, Major New Generation & Transmission expenditures continue to increase primarily due to the commencement of construction of the Bipole III Reliability project and the Keeyask Generating Station.

Figure 4.5 New Major Generation & Transmission 2013-2017

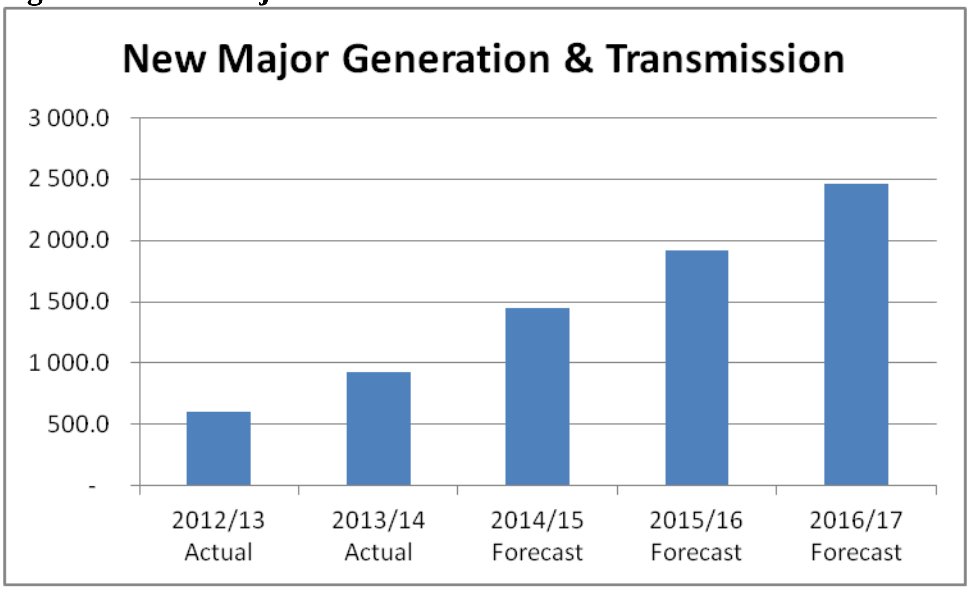


Figure 4.6 below summarizes the significant Major New Generation and Transmission capital projects.

Figure 4.6 Major New Generation & Transmission Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2023/24*
Wuskwatim - Generation	41	13	15	68
Keeyask - Generation	776	676	962	5 579
Grand Rapids Hatchery Upgrade & Expansion	2	5	9	23
Conawapa - Generation	43	31	21	96
Kelsey Improvements & Upgrades	14	9	13	37
Kettle Improvements & Upgrades	7	24	25	138
Pointe du Bois Spillway Replacement	114	52	4	170
Pointe du Bois - Transmission	16	17	14	51
Gillam Redevelopment and Expansion Program (GREP)	20	22	23	212
Bipole III - Transmission Line	203	360	381	1 514
Bipole III - Converter Stations	221	581	829	2 356
Bipole III - Collector Lines	58	76	52	227
Bipole III - Community Development Initiative	2	2	2	8
Riel 230/ 500 kV Station	36	6	-	42
Manitoba-Minnesota Transmission Project	7	33	100	348
Demand Side Management	52	59	77	676
Target Adjustment	(161)	(51)	(61)	(12)
Other	-	-	-	139
Total	**1 452**	**1 914**	**2 463**	**11 671**

* Excludes capital expenditures prior to 2013/14

The following sections provide a summary of cost updates with respect to the significant Major New Generation & Transmission projects and Electric Demand Side Management.

4.3.1 Bipole III Reliability Project

In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19, which represents a deferral of nine months from October 2017.

CEF14 incorporates a more detailed scope based on an issued Environmental Act licence, approved finalized route and right-of-way width and up-to-date market information. In addition, the revised estimate incorporates the awarding of major contracts and the selection of LCC technology, which has resulted in synchronous condensers being included in the updated estimate. The rating for the Bipole III Reliability project was increased from 2000MW to 2300MW to ensure adequate spare HVDC transmission on the northern collector system. Figure 4.7 provides an explanation of the major changes in the cost estimates.

Figure 4.7 Bipole III Reliability Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Increase	Explanation for change
HVdc Converter Stations (Riel & Keewatinohk)	1 878.3	1 208.8	669.5	- Increased for awarded contracts: HVdc Equipment, AC Switchyard, Site Development, Camp, Camp Operations, etc. - Addition of Synchronous Condensers to project scope as result of LCC converter technology selection - Increase to 2300 MW converters
500kV T-Line	1 191.0	889.0	302.0	- Increase for extended Licencing process - Increase for revised property acquisition costs - Increased clearing costs - Increase due to additional towers required
AC Collectors	198.2	115.0	83.2	- Addition of station upgrade and breaker replacement scope of work - Estimated increase to construction costs
Riel 230kV Expansion	228.7	133.4	95.3	- Increase from attribution of Riel Sectionalization costs (realized costs) - Estimated increase to construction costs
Contingency & Reserves	347.6	203.0	144.6	- Contingency & reserves included based on analysis and recommendation of 3rd party risk and contingency expert
Interest & Escalation	747.8	730.8	17.0	
Community Development Initiative	62.0	60.8	1.2	
TOTAL	**4 653.6**	**3 340.8**	**1 312.8**	

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.2 Keeyask Generating Station

In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20.

The Keeyask Project budget was updated in March 2014 as part of the Needs For and Alternatives To review. The last detailed project estimate was completed in 2009. The budget includes bid prices from the major contractors including the General Civil Contract. Figure 4.8 provides an explanation of the major changes in the cost estimates.

Figure 4.8 Keeyask Generating Station Total Project Cost Update

Cost Breakdown (in millions of dollars)	CEF 14	CEF 13	Variance	Comments
Generating Station (Including GCC and KIP)	3 681.1	3 060.6	620.5	Increase related to: - updated base expenditures from 2013$ to 2014$ on generating station and KIP - post-construction adverse effects and operational employment which were previously excluded from the estimates. Accretion is also added. - commitments made in EIS and CEC hearings related to the environment and social mitigation. - direct negotiated service contracts, interface management, forebay clearing, and community monitoring. - stage 5 engineering and construction management staff augmentation. - Increase for awarded contracts. - unforeseen conditions related to the north access road construction, and work areas site development.
Construction Power	30.4	30.4	0.0	No Change
Licensing & Planning	393.0	397.3	(4.3)	Decrease related to transfer of budget for adverse effects.
Transmission (excluding contingency)	142.1	138.3	3.8	Increase related to updated base expenditures from 2013$ to 2014$.
Contingency & Management Reserves	685.2	1 063.7	(378.5)	Decrease related to: - Contingency and labour reserve revised based on updated risk model. - Escalation reserve revised based on updated escalation reserve model.
Interest & Escalation	1 564.2	1 530.3	33.9	Increase due to Interest on higher base costs and an advanced general civil contract cash flow; partially offset by decreased Escalation indexing from the increase to 2014$.
TOTAL	**6 496.0**	**6 219.6**	**276.4**	

Note: Sunk Costs are included in each project component

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow.

4.3.3 Conawapa Generating Station

For CEF14 forecast purposes, it is assumed that the Conawapa Generating Station has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall of 2016). Remaining expenditures in the forecast include capitalized interest on construction in process through to August 2016, the wrap up of preliminary engineering studies and limited environmental and aboriginal studies.

Figure 4.9 Conawapa Total Project Cost Update

(in millions of dollars)	CEF 14	CEF 13	Decrease	Explanation
Conawapa GS	397	10 492	(10 095)	Majority of expenditures have been suspended pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in progress through August 2016.

Total project change will not tie to 10 year cost flow change shown earlier due to rollover of under expenditures in 2013/14 compared to CEF13 forecasted flow and expenditures previously forecast outside the 10 year timeframe.

4.3.4 Demand Side Management

Manitoba Hydro's DSM plan targets the achievement of 1,136 MW and 3,978 GWh of savings over the next 15 years and involves an investment of more than a billion dollars and will be relied upon to meet 66% of projected load growth during this period. Figure 4.10 provides an explanation of the major changes over the 10 year forecast period associated with the updated DSM plan.

Figure 4.10 DSM 10 Year Cost Flow Update

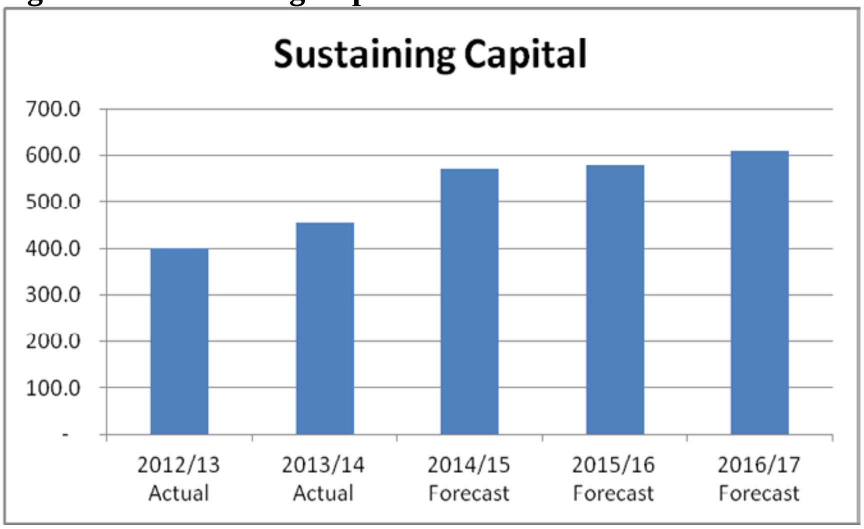
Cost breakdown (in millions) 10 Year	CEF 14	CEF 13	Increase / (Decrease)	Explanation
Residential Energy Efficiency Programs	$68.7	$4.9	$63.8	Extended and enhanced program offerings and added new programs including but not limited to introducing Residential LED Lighting program and increased insulation incentives and introduced free energy assessments for electrically heated homes.
Commercial Energy Efficiency Programs	$210.4	$69.7	$140.7	Extended and enhanced program offerings and added new programs including but not limited to adding direct installation of high efficiency pre-rinse spray valves to the Commercial Kitchen program, higher performance levels beyond the new energy code for buildings, and increased incentives and technical assistance to support energy modeling under the Commercial New Buildings program, and increased incentives under the Refrigerator Retirement, Commercial Lighting, Commercial Building Envelope, Commercial CO2 Sensors, and Commercial Refrigeration programs.
Industrial Energy Efficiency Program	$102.0	$27.7	$74.4	Enhanced program offering by expanding financial and technical support for embedded energy managers in large commercial and industrial facilities under the Industrial Performance Optimization Program.
Load Management Program	$65.8	$57.7	$8.0	Enhanced program offering by increasing incentives in the Curtailable Rates Program.
Load Displacement & Alternative Energy Programs	$97.8	$8.8	$89.0	Added customer sited load displacement program.
Conservation Rates	$26.3	-	$26.3	Added conservation rates for residential and commercial customers.
Fuel Choice Program	$55.1	-	$55.1	Added fuel choice program.
Support & Contingency	$50.1	$44.7	$5.4	Increased activities to support the enhanced DSM portfolio such as increased program evaluation activities including external evaluation consulting services.
Demand Side Management	**$676.2**	**$213.4**	**$462.8**	

4.4 SUSTAINING CAPITAL EXPENDITURES (MAJOR & BASE CAPITAL)

Sustaining capital includes items identified in CEF14 as either Major or Base capital expenditures and consists of additions, improvements and replacements of existing infrastructure.

Capital targets established for fiscal years 2014/15 through 2020/21 in CEF14 considered increased requirements for aging infrastructure based upon asset condition assessments as well as expansion requirements to support customer growth. The target adjustment of $25 million annually beginning in 2016/17 through 2020/21 provides funding to address future priorities. Investment in sustaining capital has increased $428 million over the ten year forecast period in order to maintain reliability and address anticipated load and customer growth as further discussed in Section 4.6.

Figure 4.11 Sustaining Capital 2013-2017



The following figure provides a further breakdown of sustaining capital for the first three forecast years of CEF14. Capital expenditures have been broken down by asset type, identifying the investment required to maintain reliable service.

Figure 4.12 CEF14 Sustaining Capital by Asset Type

(in millions of dollars)	2015	2016	2017
Generation Operation			
Turbines	19.7	13.4	15.8
Generators	14.4	17.8	20.1
Auxiliary Systems (Sewer, Water, Fire, etc)	12.4	10.3	12.5
Transformers	12.4	7.4	7.9
Licensing	10.4	10.8	8.3
Instrumentation & Controls	9.0	15.1	11.8
Townsite Infrastructure	8.9	10.4	5.0
Breakers	8.9	4.3	1.3
Spillway & Water Controls	7.4	13.5	24.1
Powerhouse, Dams, Dykes	6.7	7.6	8.1
Physical Security & Public Safety	5.4	3.2	2.0
AC Supporting Electrical Systems	5.2	7.6	6.4
Governors	4.6	3.9	1.6
Exciters	2.9	3.5	3.7
Tools & Equipment	2.4	2.2	1.4
Communication Systems & Equipment	1.4	1.2	1.9
	132.0	**132.0**	**132.0**
Transmission			
Station Equipment	16.3	15.2	13.9
Station Civil Infrastructure	15.9	9.1	2.8
Transformers	15.2	12.5	12.6
Communication Systems & Equipment	14.5	7.2	8.6
Protection Relays & Control, Metering & SCADA	13.8	7.2	3.2
HVDC Synchronous Condensers	9.0	8.8	2.9
Steel Structures	7.3	12.4	34.0
Wood Poles	6.7	33.2	14.1
Breakers	6.7	5.3	3.7
Battery Banks	4.0	2.5	1.9
Conductor Attachments	3.6	4.4	5.1
HVDC Valve Group	2.8	0.7	0.1
Tools & Equipment	2.4	1.6	1.4
Land & Easements	2.3	1.1	10.2
Overhead Conductors	1.8	2.4	9.5
System Control Centre	0.4	0.3	0.3
Diesel Generation	0.4	-	-
HVDC Smoothing Reactors	0.1	0.4	0.5
Other	1.8	0.9	0.1
	125.0	**125.0**	**125.0**
Customer Services & Distribution			
Poles	43.3	38.5	48.3
Overhead Conductors	39.1	33.3	33.8
Underground Cables	31.3	37.3	45.5
Station Breakers and Other Station Equipment	23.8	29.6	28.7
Overhead Transformers	22.5	18.2	22.2
Station Transformers	21.0	23.1	24.7
Padmount Transformers	17.9	12.2	15.7
Street Lights	11.0	10.8	12.8
Ductlines & Manholes	7.9	16.0	13.2
Station Site Prep	6.0	9.2	9.3
Land & Easement	3.7	0.4	0.0
Buildings	4.4	10.1	12.7
Equipment	1.4	1.2	1.4
Steel Structures	0.8	0.7	-
Other	1.3	-	-
	235.5	**240.9**	**268.3**
Customer Care & Energy Conservation			
Meters & Meter Transformers	3.2	4.0	4.1
	3.2	**4.0**	**4.1**
Human Resources & Corporate Services			
Computers & IT Systems	29.0	29.1	29.6
Buildings	22.4	24.3	9.3
Fleet	21.0	18.9	13.3
Land & Easements	1.7	1.8	1.8
Tools & Equipment	0.9	0.9	0.9
	75.0	**75.0**	**55.0**
Finance Regulatory			
Tools & Equipment	0.2	0.2	0.2
	0.2	**0.2**	**0.2**
Target Adjustment	-	-	25.0
Sustaining Capital Total	**570.9**	**577.0**	**609.6**

4.5 CAPITAL IN-SERVICE

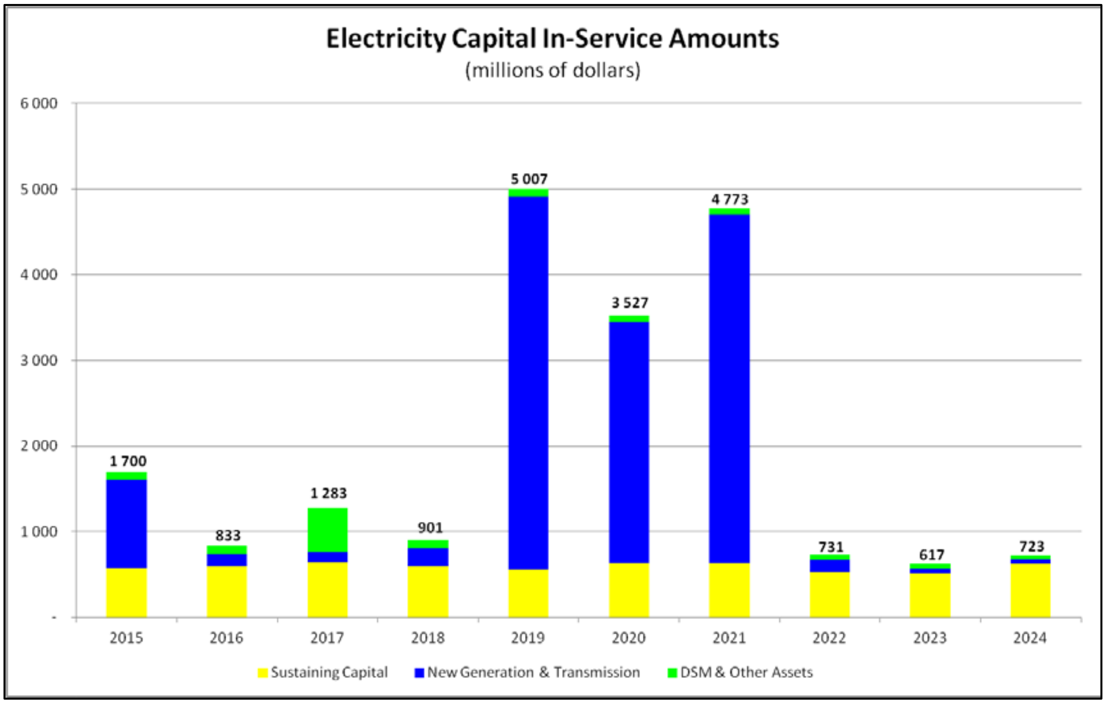
While assets are under construction, the capital expenditures and associated financing costs are held in construction work in progress. Once these assets are placed into service, the associated carrying costs (depreciation and finance expense) form part of the Corporation's revenue requirements.

Figures 4.13 and 4.14 provide a summary of the amount of capital that is forecast to go in service, as well as deferred assets that will commence amortization for the first three forecast years as well as the 10 year forecast period. Figure 4.13 indicates that $1.7 billion, $0.8 billion and $1.3 billion of assets are projected to be placed in-service in 2014/15, 2015/16 and 2016/17 respectively. The most significant assets being placed in-service during this period include the Pointe du Bois spillway replacement, and the Riel 230/500kV Station in 2014/15. In this three year period, there is also approximately $1.8 billion of sustaining capital expenditures that will be placed into service, and $0.2 billion of DSM expenditures that will commence amortization.

Figure 4.13 Electricity Capital In-Service Amounts

(millions of dollars)	2015	2016	2017	Cumulative 10 Year Total
Wuskwatim - Generation	40	4	26	70
Keeyask - Generation	-	-	-	6 496
Grand Rapids Hatchery Upgrade & Expansion	-	-	-	24
Kelsey Improvements & Upgrades	17	8	15	41
Kettle Improvements & Upgrades	6	24	24	141
Pointe du Bois Spillway Replacement	477	91	4	572
Pointe du Bois - Transmission	21	0	10	59
Gillam Redevelopment and Expansion Program (GREP	18	24	24	210
Bipole III - Transmission Line	0	0	-	1 593
Bipole III - Converter Stations	123	-	-	2 657
Bipole III - Collector Lines	4	-	13	260
Bipole III - Community Development Initiative	-	-	-	62
Riel 230/500kV Station	329	0	-	330
Manitoba-Minnesota Transmission Project	-	-	-	349
Generating Station Improvements & Upgrades	-	-	-	139
New Generation & Transmission Sub Total	**1 036**	**152**	**116**	**13 003**
				-
Demand Side Management	52	59	77	676
Conawapa - Generation	-	-	397	397
Other	36	29	53	138
DSM & Other Assets Sub Total	**88**	**89**	**526**	**1 211**
				-
Generation Operations	154	188	85	1 466
Transmission	88	94	168	1 346
Customer Service & Distribution	259	234	296	2 303
Customer Care & Energy Conservation	3	4	4	39
Human Resources & Corporate Services	72	73	64	600
Finance & Regulatory	0	0	0	2
Target Adjustment	-	-	25	125
Sustaining Capital Sub Total	**576**	**593**	**642**	**5 882**
				-
TOTAL	**1 700**	**833**	**1 283**	**20 096**

Figure 4.14 Electricity Capital In-Service Amounts 2014/15-2023/24



4.6 INVESTING TO MAINTAIN RELIABLE SERVICE

Manitoba Hydro's asset management has enabled the Corporation to defer hundreds of millions of dollars of capital investment to date. However, increased investments are required for generation, transmission and distribution system renewal and capacity expansion in order to support the growth requirements of Manitoba Hydro's customers. These capital investments are needed to sustain the Corporation's current electric infrastructure considering the increasing pressures associated with aging infrastructure and the need to provide more capacity to accommodate increased demand resulting from increased population and business growth. CEF14 forecasts capital expenditures of $493 million, $498 million and $525 million in 2014/15, 2015/16, and 2016/17, respectively for investment in generation, transmission and distribution assets (does not include expenditures associated with corporate infrastructure).

4.6.1 Impacts of Aging Infrastructure on Reliability

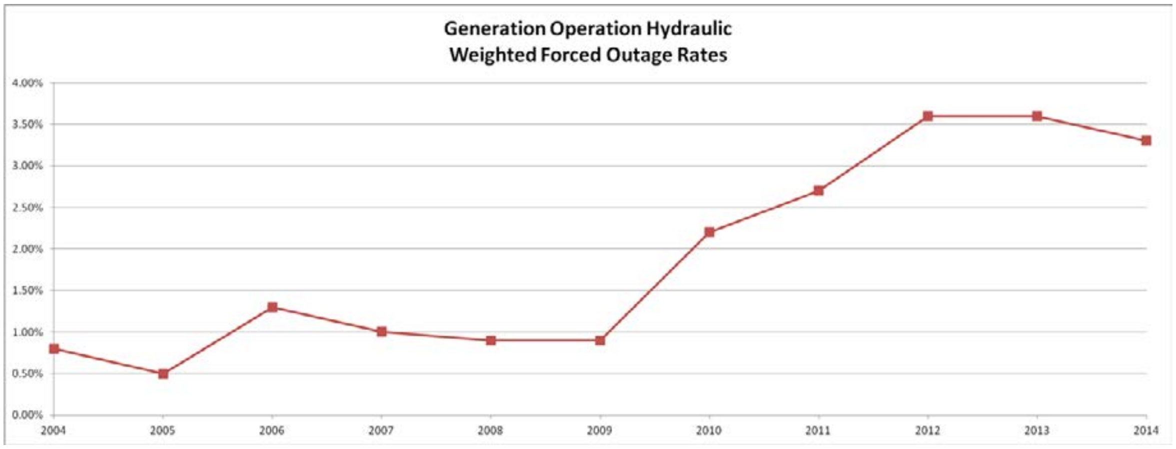
Manitoba Hydro has prudently invested in the electrical system which has provided reliable service to customers for decades. Where system reliability risk dictates, Manitoba

Hydro has installed redundant capacity to ensure that it can supply load in the event of an outage in an acceptable timeframe. Contingency plans, such as the transfer of load to available stations, the use of mobile stations, and allowing temporary overloads on equipment where it can be determined that such overloads are not expected to appreciably reduce equipment life, allow the Corporation to supply load at acceptable voltage levels after a system outage occurs.

In the past, Manitoba Hydro has been able to effectively deal with capacity challenges on its system by taking advantage of redundant capacity and contingency plans which has allowed the Corporation to defer capacity upgrades while maintaining reliability levels. However, the number of areas of the electric system with capacity challenges is growing, and this is the result of an aging system and strong load growth in some parts of the Province. Consequently, Manitoba Hydro's ability to respond to these challenges without negatively impacting reliability is diminishing.

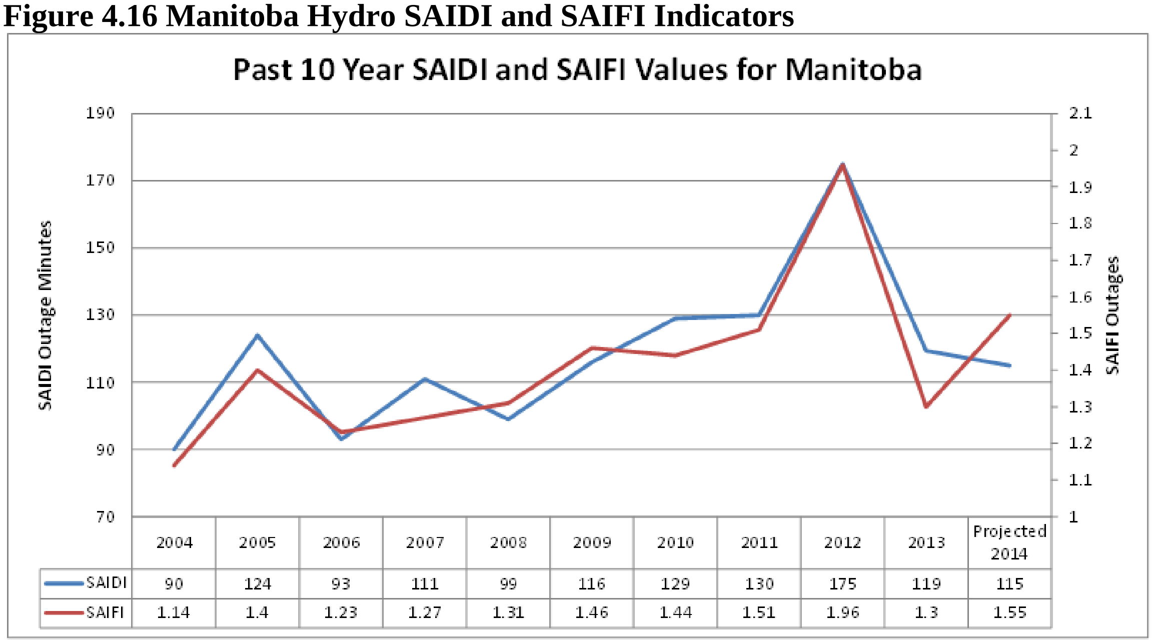
Reliability is critical for Manitoba Hydro and its customers. Historically, the reliability performance of Manitoba Hydro's electric system has been excellent, but has recently begun to degrade. While reliability is impacted by factors such as adverse weather, tree contacts, and the lengthening of restoration time due to changes in work procedures to conform to safety, legal and environmental requirements, the condition of Manitoba Hydro's assets is contributing more and more to the decline in reliability. This is evident in Manitoba Hydro's performance in key reliability indicators. As illustrated in Figure 4.15 below, generation forced outage rates have significantly increased in the past four years.

Figure 4.15 Hydraulic Generation Forced Outage Rates



Likewise, Manitoba Hydro's recent performance on the System Average Interruption Duration Index (SAIFI) and the System Average Interruption Frequency Index (SAIDI) indicators (with the exception of 2013 which reflects lower than normal storm activity) shows a trend of increased outage frequency and duration.

Figure 4.16 Manitoba Hydro SAIDI and SAIFI Indicators



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Projected 2014
SAIDI	90	124	93	111	99	116	129	130	175	119	115
SAIFI	1.14	1.4	1.23	1.27	1.31	1.46	1.44	1.51	1.96	1.3	1.55

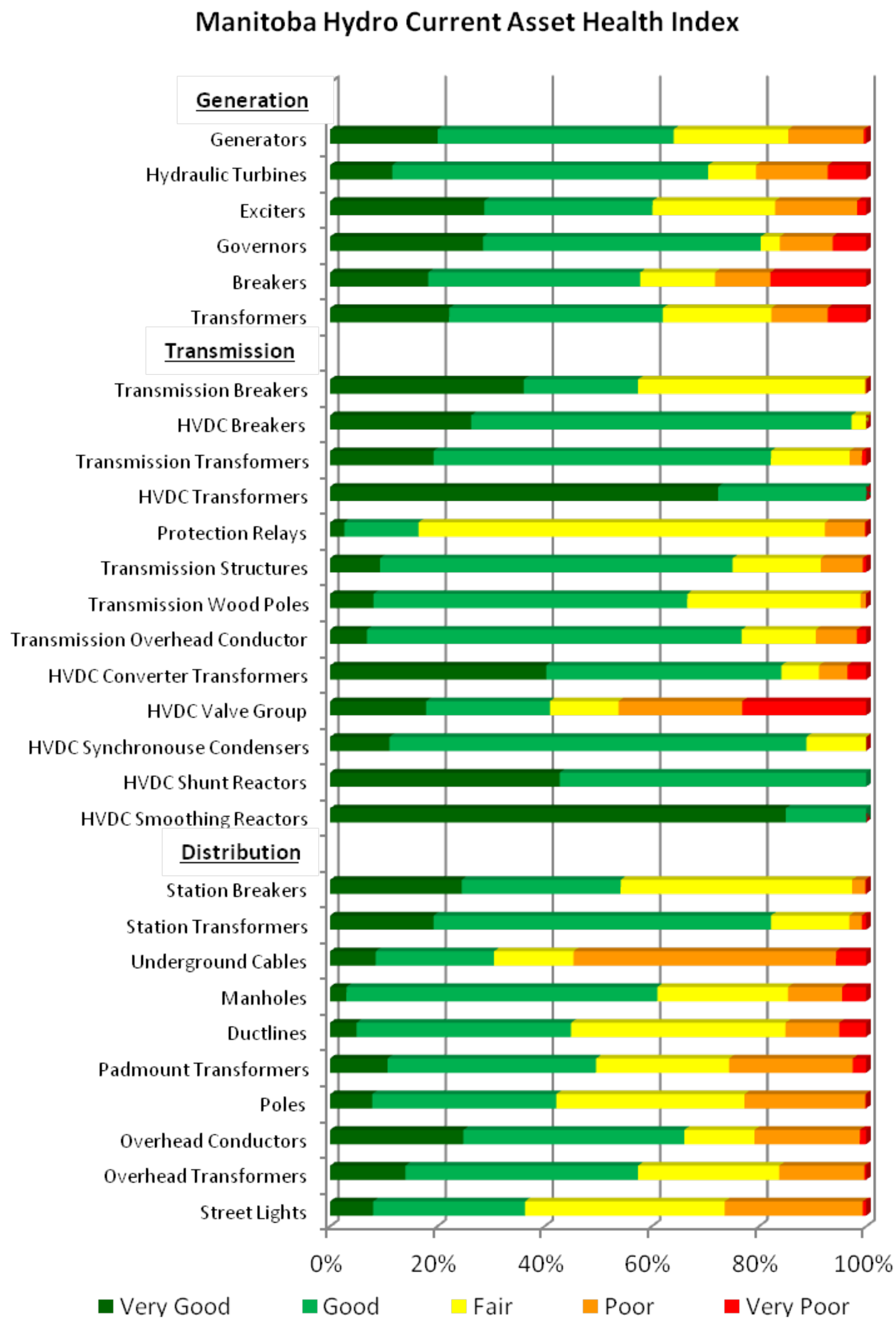
Manitoba Hydro has been taking actions for many years to mitigate the impacts of aging infrastructure on reliability performance, such as implementing an integrated pole maintenance program that has allowed the Corporation to extend the pole asset serviceable life well-beyond industry standards, and more recently, leveraging cable silicone injection technology to extend the serviceable life of underground cables. However, significant capital investments are required to address aging infrastructure and increased capacity needs on the system.

A considerable amount of Manitoba Hydro’s assets were installed prior to 1960 when many of the first generating stations and transmissions systems were built (1911-1950) and a large portion of the province was electrified (1940-1960). Many of these assets have been well maintained or overhauled and are still in operation, providing decades of valuable service to the Corporation and its ratepayers. A large number of assets were subsequently installed from 1960 through to 1990 when generating stations were developed on northern Manitoba river systems along with the supporting HVDC system to transport the electricity to customers in the south.

Many components of this generation, transmission and distribution system are coming due for replacement, with some components requiring investments in the short term. Some of Manitoba Hydro’s assets are in poor condition with ages well beyond industry standards and present a significant risk of failure which can result in customer outages and/or load shedding. Some of these assets types, such as breakers, generators, wood poles and valve groups, also require significant resources, lead time and capital investment to address their present condition. Though assets are being continually maintained, current levels of system reliability will not be sustained with current asset replacement rates.

As Appendix 4.2 to this Tab, Manitoba Hydro has included its Electric Infrastructure Condition Assessment Report. The report provides an overview of the condition of major electrical assets and their demographics, as well as an overview of critical assets’ life expectancy versus the current replacement rates and the quantities of assets in critical condition. Manitoba Hydro used an Asset Health Index (AHI) to quantify equipment condition based on numerous parameters, as described in section 3 of Appendix 4.2. A condition index was calculated for each asset indicating whether the asset type is in very poor, poor, fair, good or very good condition. Figure 4.17 below provides a summary of current AHI results for Manitoba Hydro’s generation, transmission and distribution asset types.

Figure 4.17 Current Asset Health Index by Asset Type



Manitoba Hydro can effectively manage its assets through the use of maintenance, spares and contingency strategies when the majority of assets in a particular asset class are in fair to very good condition. However, as larger percentages of these assets fall into the poor and very poor categories, system failures regretfully will occur more frequently.

It is notable that the majority of critical assets are being replaced at levels substantially less than their anticipated lifespan. Today, a majority of the asset types have equipment which remains in service well beyond industry expectations, without causing significant impact to reliability. Going forward, as a larger percentage of assets age beyond life expectancy, significant changes to current replacement rates[1] will be required to mitigate the negative impacts of aging infrastructure on the electrical system. Figure 4.18 illustrates turnover at current replacement rates[2], indicating that replacement rates in the majority of Manitoba Hydro's asset types need to be increased to better align with life expectancy.

Figure 4.18 Asset Type Life Expectancy and Turnover at Current Replacement Rates

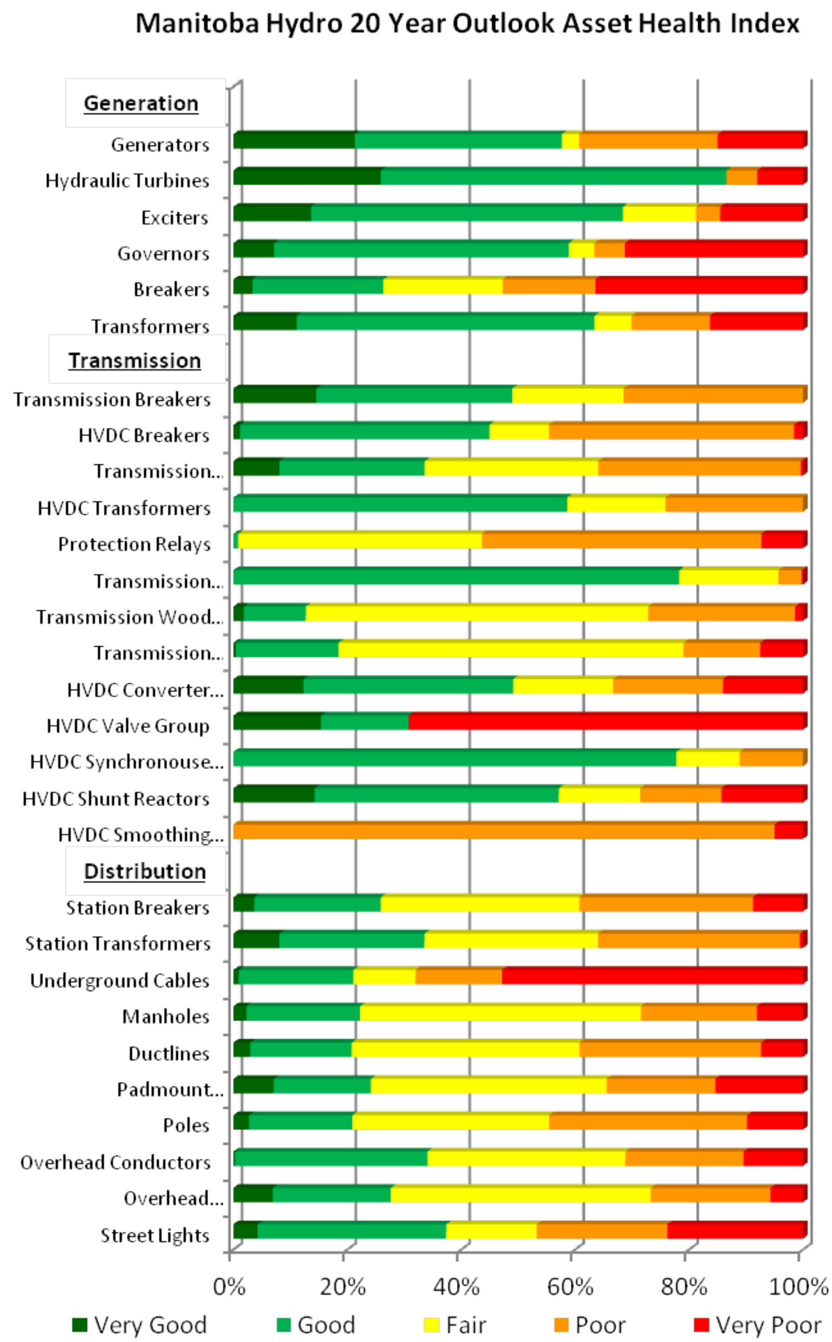
Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Generation	Generators	60	117
	Hydraulic Turbines	90-100	84
	Exciters	50-90	117
	Governors	20-125	50
	Breakers	60-65	129
	Transformers	40-70	150
Transmission	Transmission Breakers	60-65	149
	HVDC Breakers	60-65	58
	Transmission Transformers	40-70	152
	HVDC Transformers	40-70	70
	Transmission Structures	85	285
	Transmission Wood Poles	75	255
	Transmission Overhead Conductor	85	410
	HVDC Converter Transformers	40-50	73
	HVDC Valve Group	25	48
	HVDC Synchronouse Condensers	65	65
	HVDC Shunt Reactors	35	55
	HVDC Smoothing Reactors	25	30

[1] The replacement rate is the average number of assets replaced each year divided by the total number of in service assets.
[2] Turnover at Current Replacement Rate is the number of years it would take to replace all our existing in service assets at current replacement rates.

Business Unit	Asset	Life Expectancy (years)	Turnover at Current Replacement Rates (years)
Distribution	Station Breakers	60-65	180
	Station Transformers	40-70	370
	Underground Cables	30-70	328
	Manholes	80	500
	Ductlines	100	378
	Padmount Transformers	50	70
	Wood Poles	70	200
	Overhead Conductors	100	200
	Overhead Transformers	75	70
	Street Lights	50-70	100

The original cost of Manitoba Hydro's electric assets is approximately $16 billion with an estimated replacement value many multiples higher due to inflation, increases in commodity prices and other factors. An asset portfolio of this size requires significant reinvestment to ensure that performance and safety standards are achieved. As a result, it is essential that investments on asset renewal be undertaken. Manitoba Hydro will continue to extend the life of its assets to the extent feasible based on economic and risk assessments, however, current replacement rates do not allow for a sustainable electrical system in the near future. Figure 4.19 demonstrates the impact to asset health if current replacement rates are maintained, indicating a trend toward less asset reliability as more slip into the poor and very poor condition.

Figure 4.19- 20 Year Outlook Asset Health Index by Asset Type



As discussed in Appendix 4.2, it is expected that over the next 20 years more assets will slip into poor and very poor condition, which will result in lower reliability than experienced historically, reduced revenues, increased safety risks to public and employees, increased maintenance costs, increased emergency restoration costs and consequential damages. In addition, internal resource levels to address both maintenance and asset replacement requirements would be strained and the ability to secure external resources may be limited.

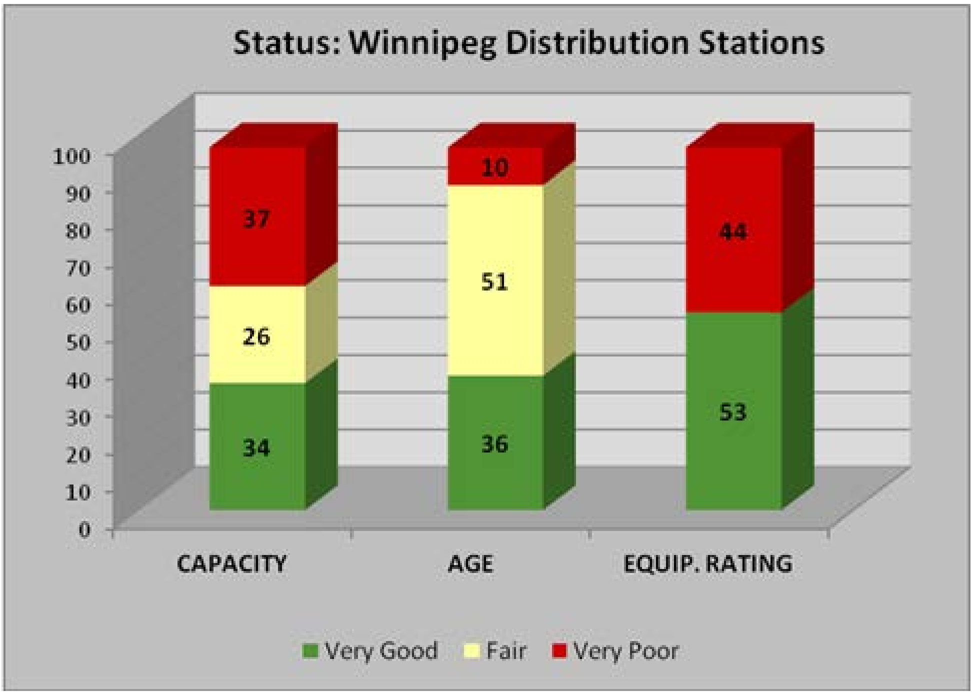
4.6.2 Capacity Constraints Impacting System Performance & Customer Growth

In conjunction with the impacts of aging infrastructure, Manitoba Hydro is facing significant capacity issues. Electric load in an increasing number of service areas has grown to the point where Manitoba Hydro may not be able to adequately supply load in the event of an outage despite contingency plans. Capacity challenges also make it more difficult to respond to customer connection requests. The Corporation has identified a number of capital investment priorities for its distribution and transmission systems related to capacity and investments are being undertaken and will be required in the near future to address these capacity issues.

For example, significant capital investment in distribution stations in Winnipeg and rural Manitoba is required as a large number of the stations are currently overloaded. There are 276 distribution stations in rural Manitoba; 19 of these are loaded above their maximum capacity, while 27 stations are at or above 80% of their loading limit. There are areas of the Province experiencing load growth much higher than the system average. In addition, there are areas of the province where the distribution system is near its end of life. In areas where these issues intersect, investment requirements become more important, such as in the Steinbach area, the Morden/Winkler area, Western oil fields, Brandon South and the Eastern Lake Winnipeg Area. As is noted below, the transmission system that supports the distribution in these areas is also facing capacity challenges.

Likewise, current Winnipeg distribution system capacity is not sufficient to meet current or future loads, which results in a high likelihood of extended outages to customers. Figure 4.20 provides an overview of the current status of the distribution system in the City of Winnipeg.

Figure 4.20 Status of Distribution Stations in Winnipeg



There are 97 distribution stations supplying the City of Winnipeg; 37 stations are currently loaded beyond their maximum capacity, and 26 stations are at or above 80% of their loading limit. The in-service dates of substation capacity projects can be deferred by transferring load to other, less loaded stations; however, the use of this strategy has been exhausted and is no longer practical. Contingency plans have become ineffective to restore full load in the event of an outage. Furthermore, ten of the distribution stations are 61 years or older, exceeding the design life of the equipment, and 44 stations have fault levels that exceed equipment ratings under certain operating conditions, such as during extreme low temperatures where electrical demand is typically highest.

Based on current capital plans, Manitoba Hydro is working towards reducing the percentage of overloaded distribution stations in Winnipeg to 20% by 2020 and in rural Manitoba by 5% in 2015 with a long term objective of ensuring that no stations exceed their maximum rating. Achieving this objective requires significant investments today and in the coming years. This issue is of significant concern, not only as it limits Manitoba Hydro's ability to supply electricity reliably to existing customers, but also in light of the expected load additions in many areas of the Province, including downtown Winnipeg where load additions are much larger than anticipated. It is estimated that service extensions are required for approximately 5,300 new electric customers each year across the Province.

Similarly, Manitoba Hydro's transmission system is facing significant capacity issues. There are a number of areas in the transmission system where significant investments are required in order to address higher than average load growth, deteriorating voltage levels, and/or impacts of increasing transmission system capacity on some existing system equipment. Manitoba Hydro has also identified a number of high-priority transmission capital investments to address capacity requirements that will need to be undertaken.

As noted above, Manitoba Hydro has experienced higher than average load growth in areas such as the eastern Lake Winnipeg area, the Winkler/Morden area, and the Steinbach area which exceed the firm capacity of its stations, and/or result in low voltage issues. In the Eastern Lake Winnipeg, load has grown beyond the maximum capacity of Pine Falls Station, a key station that supplies the area, and over the next several years, the load is expected to grow to the point that overloads could not be reduced to acceptable levels by transferring load to other stations, potentially resulting in transformer damage or rotating load shed in a difficult to serve region of the Province.

With respect to the Morden/Winkler area, the 115 kV transmission system supplying the area can experience low voltage issues, particularly during peak load conditions and outages on the system. In such cases, rotating load shed during peak winter loading conditions may be required to restore system voltages to acceptable levels.

Likewise, the Winnipeg area has become heavily loaded due to load growth and upgrades to the transmission system are required, including the construction of a new transmission line, in order to protect against blackouts, and improve the system performance and reliability during normal operations as the load grows in southern Manitoba. In addition, as the capacity of the Winnipeg area transmission system continues to increase, the ratings of some system protection/interrupting equipment in the area are expected to be exceeded. This necessitates the replacement of breakers in order to avoid potential harm to employees, the public and infrastructure.

As well, steady load growth in Western Manitoba has resulted in deteriorating voltages on the transmission system in the Portage South area, which is impacting local load and Saskatchewan export capabilities and the ability to supply new oil pipeline related load.

If the capacity-related projects are not undertaken, customers in the impacted areas would be at a higher risk of extended outages and there is a risk that Manitoba Hydro could potentially be subject to significant financial penalties if having to report North American Electric Reliability Corporation violations.

Addressing the above matters will require investments in new transmission lines, investments to address station overloading, capacity upgrades and new construction to accommodate future load growth.

The continued provision of safe and reliable service requires Manitoba Hydro to undertake investments today and in the near future. The proposed rate increases will ensure that there is adequate funding available to make the necessary investments.

December 2014

Capital Expenditure Forecast (CEF14)

2014/15 - 2033/34

Finance & Regulatory

Manitoba Hydro

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

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Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Section 1

Overview

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1.0 Overview

The Capital Expenditure Forecast (CEF14) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in the Capital Expenditure Forecast will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner.

The Capital Expenditure Forecast is comprised of a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major items are normally greater than $50 million in total cost and the construction period on each major item usually extends beyond one year. Base capital expenditure items typically represent sustaining capital requirements to meet electricity and natural gas service replacements and expansions throughout the province. All major and base capital projects are subjected to a rigorous review and approval process before being included in the Capital Expenditure Forecast

The CEF14 includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19. In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20. Manitoba Hydro continues to develop the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation. The Province also endorsed Manitoba Hydro's new, more aggressive demand side management PowerSmart plan which targets a 250% increase in consumption savings.

For CEF14 forecast purposes, it is assumed that the Conawapa Generating Station has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall of 2016).

Base capital targets established for fiscal years 2014/15 through 2020/21 in CEF14 considered increased requirements for aging infrastructure based upon asset condition assessments. Beginning in 2021/22, base capital targets are escalated at a minimum 2% annually.

Capital Expenditure Forecast Summary

The CEF14 totals $25 953 million for the twenty year period to 2033/34. Expenditures for Major New Generation & Transmission (MNG&T) total $12 611 million, with the balance of $13 342 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

Comparison to CEF13

The CEF14 for the twenty year period to 2033/34 totals $25 953 million compared to $33 474 million for the same twenty year period included in last year's Capital Expenditure Forecast (CEF13).

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	2 359	21 191
Incr (Decr)	9	73	580	803	52	(408)	(333)	(962)	(1 595)	(1 635)	(3 416)
CEF14	2 071	2 556	3 124	3 161	2 113	1 470	1 039	793	724	724	17 774

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
CEF13	2 162	2 048	1 838	1 399	1 098	922	828	680	630	679	33 474
Incr (Decr)	(1 384)	(1 264)	(1 054)	(623)	(305)	(151)	(8)	154	245	285	(7 521)
CEF14	778	784	785	776	793	771	820	834	875	963	25 953

The following table provides a summary of the major changes to CEF14.

	Total Projected Cost	10 Year Increase (Decrease)	20 Year Increase (Decrease)
	($ Millions)		
Conawapa - Generation	397	(6 052)	(10 065)
Base Capital Target	NA	422	1 957
Pointe du Bois Powerhouse Rebuild	1 852	(19)	(1 471)
Bipole III - Converter Stations	2 675	881	881
Demand Side Management *	NA	463	802
Additional North South Trasmission	-	(90)	(475)
Bipole III - Transmission Line	1 655	407	407
Keeyask - Generation	6 496	349	349
Gillam Redevelopment and Expansion Program	266	(77)	(100)
Gas Demand Side Management *	NA	50	92
Bipole III - Collector Lines	260	71	71
Dorsey 230KV Zone Building	-	(63)	(63)
New Adelaide Station - 66/12kV	62	62	62
Slave Falls Major Overhauls	126	(63)	-
Other System Upgrades		243	32
		(3 416)	(7 521)

*Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under the interim standard that continues to permit rate regulated accounting.

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	776.3	676.3	962.2	1 351.3	927.9	616.5	208.6	55.2	4.5	0.1	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GREP)	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1 655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 451.7**	**1 913.9**	**2 463.5**	**2 577.8**	**1 530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11 670.7**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1 336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1 350.0**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1 965.3
Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2 211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5 535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6 103.4**
CONSOLIDATED CEF14 TOTAL		**2 070.6**	**2 555.8**	**3 123.6**	**3 161.5**	**2 113.0**	**1 469.6**	**1 038.7**	**792.8**	**724.1**	**724.4**	**17 774.1**
ELECTRIC CAPITAL TOTAL		**2 022.6**	**2 490.9**	**3 073.1**	**3 125.2**	**2 078.3**	**1 431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17 331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	-	-	-	-	-	-	-	-	-	-	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GREP)	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1 655.4	-	-	-	-	-	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	-	-	-	-	-	-	-	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1 186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12 611.1**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
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CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2 290.6
Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2 900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2 452.3
Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3 025.3**

Manitoba Hydro
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CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4 773.2
Total	**NA**	**261.6**	**257.8**	**263.3**	**267.2**	**285.6**	**268.1**	**298.7**	**297.6**	**302.6**	**305.3**	**5 019.6**
Customer Care & Energy Conservation	**NA**	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**81.0**
Human Resources & Corporate Services	**NA**	**59.5**	**60.7**	**61.9**	**63.2**	**64.4**	**65.7**	**67.0**	**68.4**	**69.8**	**71.1**	**1 248.6**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**4.9**
		621.1	**624.5**	**637.3**	**648.6**	**674.7**	**665.0**	**703.5**	**710.5**	**723.8**	**734.9**	**12 279.9**
Gas												
Customer Service & Distribution	**NA**	**33.7**	**33.5**	**34.0**	**34.7**	**36.6**	**34.1**	**38.2**	**39.3**	**40.2**	**41.0**	**664.1**
Customer Care & Energy Conservation	**NA**	**5.4**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**106.8**
Gas Demand Side Management	**NA**	**9.6**	**9.8**	**10.0**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**165.9**
		48.7	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**669.8**	**673.2**	**686.9**	**694.7**	**722.8**	**710.8**	**753.6**	**761.9**	**776.3**	**788.4**	**13 341.7**
CONSOLIDATED CEF14 TOTAL		**777.6**	**783.9**	**784.7**	**776.0**	**793.3**	**771.5**	**820.1**	**833.5**	**874.7**	**963.4**	**25 952.9**
ELECTRIC CAPITAL TOTAL		**728.9**	**735.1**	**735.1**	**729.9**	**745.3**	**725.7**	**770.0**	**782.2**	**822.2**	**910.0**	**25 016.1**
GAS CAPITAL TOTAL		**48.7**	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**

Section 2

Project Summaries

ELECTRIC OPERATIONS:

MAJOR NEW GENERATION & TRANSMISSION:

Wuskwatim - Generation

Description:
Design and build the new Wuskwatim generating station with three generators and installed capacity of approximately 200MW on the Burntwood River upstream of Thompson.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power June 2012

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 448.6	$ 23.8	$ 12.1	$ -	$ -	$ -	$ -
Increase (Decrease)	-	16.7	0.8	14.7	-	-	-
Revised Forecast	$ 1 448.6	$ 40.5	$ 12.9	$ 14.7	$ -	$ -	$ -

Keeyask - Generation

Description:
Design and build the Keeyask generating station with seven generators and nominal capacity of 695MW on the Nelson River downstream of the Kelsey generating station. Project costs also include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. These costs are comprised of extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power November 2019

Revision:
The Keeyask Project control budget was updated in March 2014 as part of the NFAT review of the preferred development plan. The last detailed project estimate was completed in 2009. The control budget includes bid prices from the major contractors including the General Civil Contract, current budget of the Keeyask Infrastructure Project and cost flow revisions.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 6 220.1	$ 471.0	$ 639.3	$ 865.1	$ 1 111.4	$ 942.3	$ 1 201.1
Increase (Decrease)	276.0	305.3	37.1	97.1	239.9	(14.4)	(316.3)
Revised Forecast	$ 6 496.1	$ 776.3	$ 676.3	$ 962.2	$ 1 351.3	$ 927.9	$ 884.8

Grand Rapids Hatchery Upgrade and Expansion

Description:
Expand the capacity of the existing facility through tank replacement/reconfiguration and upgrade of supporting water treatment infrastructure. Modifications to the Research Centre (a separate facility on the GRH site), including well and potable water supply, to serve as a temporary production facility during hatchery upgrade and expansion, and the purchase of portable satellite facilities to allow for fish rearing during hatchery construction. Install electrical service from Grand Rapids Generating Station service to the hatchery.

Justification:
Upgrades to the Grand Rapids hatchery are a requirement of the Keeyask Environment Act licence as well as recently introduced national and provincial regulatory requirements for water quality and biosecurity.

In-Service Date:

March 2018

Revision:
New item.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	23.5	1.9	4.7	9.3	6.8	-	-
Revised Forecast	$ 23.5	$ 1.9	$ 4.7	$ 9.3	$ 6.8	$ -	$ -

Conawapa - Generation

Description:
Design and build the Conawapa generating station with ten generators and nominal capacity of 1 485MW on the Nelson River downstream of the Limestone generating station. Project costs also include activities associated with extensive First Nations and other community consultations, pre-project training, environmental studies, impact statement preparations, submissions, regulatory review processes, acquiring all necessary licensing, improvements to access roadways, and detailed pre-engineering required to obtain a license and all necessary approvals to construct the Conawapa generating station.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
Under review pending re-evaluation of the business case.

Revision:
Majority of expenditures have been suspended pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in process through August 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 10 491.5	$ 70.1	$ 125.9	$ 99.4	$ 240.6	$ 308.1	$ 9 317.0
Increase (Decrease)	(10 094.5)	(26.7)	(94.5)	(78.4)	(240.6)	(308.1)	(9 317.0)
Revised Forecast	$ 397.0	$ 43.4	$ 31.4	$ 21.0	$ -	$ -	$ -

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all seven Kelsey generating station units including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform extensive intake gate rehabilitation, perform draft tube modifications, perform an 8 000 hour inspection, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey generating station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77MW of additional Kelsey output.

In-Service Date:
October 2016

Revision:
In July 2013, the overhauls on all seven units had been completed and placed back in-service. Significant work remains to fix deficiencies on the head covers of all the units to improve safety and reliability. Wastewater treatment upgrades, required to accommodate the increased workforce during the overhauls, was higher than anticipated due the original design not meeting environmental limits. Final In-service date deferred 26 months from August 2014.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 301.7	$ 2.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	39.0	11.9	9.1	12.9	1.3	-	-
Revised Forecast	$ 340.4	$ 14.1	$ 9.1	$ 12.9	$ 1.3	$ -	$ -

Kettle Improvements & Upgrades

Description:
Rewind stator for units 5-12 and install a new stator frame, core and winding for units 1-4. Perform rotor refurbishment, thrust runner replacement, new excitation transformers, rebabbitting of bearings, excitation upgrade replacements, control and protection system replacements, mechanical systems replacements, and intake gate and wicket gate work for units 1-4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Re-wedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Unit 4 requires repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core.

In-Service Date:
March 2026

Revision:
To reflect final costs for Unit 4, including scope increase for thrust runner replacement, new excitation transformer, re-babbiting of bearings and removal and disposal of the old stator for units 1-4.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 165.7	$ 7.7	$ 23.7	$ 17.3	$ 1.0	$ 31.7	$ 29.5
Increase (Decrease)	25.9	(1.1)	(0.2)	7.3	21.0	-	(0.0)
Revised Forecast	$ 191.6	$ 6.6	$ 23.5	$ 24.6	$ 22.0	$ 31.7	$ 29.5

Pointe du Bois Spillway Replacement

Description:
Design and build a new spillway and new concrete and earth fill dams to replace the existing spillway structures. Includes engineering and environmental studies, community consultation, obtaining regulatory approval, and de-commissioning the existing spillway.

Justification:
Pointe du Bois does not currently meet dam safety guidelines with respect to spillway capacity. A new spillway is required to meet these guidelines.

In-Service Date:
October 2015

Revision:
Deferred spillway in-service due to a late start to concrete placement, lower than planned productivity pushing concrete work into winter months and increased gate installation time. In addition to the delay in the spillway in-service, dam placement activities were suspended due to the late spring melt and higher than average precipitation flows on the Winnipeg River. As a result, final in-service date deferred one year from October 2014.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 559.6	$ 125.3	$ 5.5	$ -	$ -	$ -	$ -
Increase (Decrease)	15.0	(11.2)	46.1	3.8	-	-	-
Revised Forecast	$ 574.8	$ 114.1	$ 51.6	$ 3.8	$ -	$ -	$ -

Pointe du Bois - Transmission

Description:
Redevelop Stafford Terminal station (formerly Scotland station), replace Bank 7 at Pointe du Bois switchyard station, salvage 66kV P lines between Pointe du Bois and Rover stations, install a 115kV transmission line between Pointe du Bois and Whiteshell stations, add Bank 8 to Pointe du Bois switchyard, install a 66kV line between Ridgeway and Rover stations, and upgrade protection at Slave Falls switchyard station.

Justification:
The 66kV lines P1, P2, P3, and P4 between Pointe du Bois and Rover stations have exceeded their expected serviceable life and pose threats to public and employee safety. The reliability of the transmission system in the Winnipeg Central area has been degraded due to the poor physical condition of these lines. In order to successfully operate the power system and continuously deliver high quality power to our customers and protect the public, the P Lines should be removed. The rebuild of Stafford station is required to address due diligence concerns, including Manitoba Hydro grounding and switching standards and public safety, and to increase Winnipeg Central capacity. This work involves converting the 138kV system to 115kV, so work at Pointe du Bois is also required.

In-Service Date:
December 2017

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 114.3	$ 8.6	$ 12.3	$ 21.9	$ 7.4	$ -	$ -
Increase (Decrease)	-	7.2	4.8	(8.2)	(3.1)	-	-
Revised Forecast	$ 114.3	$ 15.8	$ 17.1	$ 13.8	$ 4.3	$ -	$ -

Gillam Redevelopment and Expansion Program (GREP)

Description:
Redevelop and expand the Town of Gillam infrastructure in Phases 1B, 2 and 3. Phases 2 & 3 will require further definition based on conceptual design and the requirement of Manitoba Hydro's construction of new facilities in the North.

Justification:
Redevelopment of the Town of Gillam is required to address existing operational needs and to prepare for the growth associated with new generation facilities. The GREP will improve the overall quality of infrastructure in Gillam, which will positively affect attraction and retention for existing and new generation facilities. The GREP supports Corporate initiatives to develop the hydroelectric potential of the Lower Nelson River.

In-Service Date:
March 2027

Revision:
A re-evaluation of the project resulted in cost reductions due to optimization of the project through a redesign of the town centre, residential site development, trailer park and industrial park as well as a re-analysis of customer requirements resulting in a reduction in scope of work.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 366.5	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 27.9	$ 221.3
Increase (Decrease)	(100.0)	(7.0)	(7.8)	(7.8)	(7.8)	(7.7)	(62.0)
Revised Forecast	$ 266.5	$ 20.0	$ 22.4	$ 22.8	$ 21.8	$ 20.2	$ 159.3

Bipole III - Transmission Line

Description:
Design and build a +/- 500kV HVdc transmission line of approximately 1 341km (west of Lakes Winnipegosis & Manitoba) from Riel Converter Station to Keewatinohk Converter Station. Conduct environmental impact assessment, acquire property, and obtain licensing necessary for a +/- 500kV DC transmission line and converter stations at Riel and Keewatinohk.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power, due to decreased line losses (approximately 76MW under full existing generation). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage.

In-Service Date:
July 2018

Revision:
The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. The project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 259.9	$ 265.9	$ 381.9	$ 263.7	$ 195.2	$ -	$ -
Increase (Decrease)	395.5	(62.4)	(21.5)	117.3	298.6	75.3	-
Revised Forecast	$ 1 655.4	$ 203.5	$ 360.5	$ 381.0	$ 493.8	$ 75.3	$ -

Bipole III - Converter Stations

Description:
Design and build an HVdc converter station with a rating of 2300MW at the proposed Keewatinohk (Keewatinoow) site, including property acquisition costs and the Keewatinohk 230kV AC switch yard. Design and build an HVdc converter station with 2300MW of converters at Riel, including four LCC HVdc synchronous condensers, property acquisition costs and expansion of the Riel 230kV AC switch yard.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole I and II) corridor outage or a Dorsey station common mode outage. The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage.

In-Service Date:
July 2018

Revision:
The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 1 828.5	$ 262.6	$ 493.2	$ 410.2	$ 181.5	$ 127.4	$ -
Increase (Decrease)	846.6	(41.6)	87.6	418.5	326.1	67.7	23.0
Revised Forecast	$ 2 675.1	$ 221.1	$ 580.8	$ 828.7	$ 507.7	$ 195.1	$ 23.0

Bipole III - Collector Lines

Description:
Design and construct three permanent and two temporary 230kV collector lines for the Keewatinohk Converter Station. Construct power substation for the Keewatinohk Converter Station, 138 kV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station. Design and construct the Riel and Keewatinohk electrode lines, sectionalize the 230kV transmission line R49R at Riel. Includes the property acquisition and/or easements for the collector lines and the electrode lines. Design and construct a new bay and modify existing Long Spruce 230 KY AC switchyard for the new collector line to Keewatinohk Converter Station. Design and construction of a new bay and modifications at existing Henday 230 KY AC switchyard for the four new collector lines to Keewatinohk Converter Station. Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
July 2018

Revision:
The revised estimate incorporates a more detailed scope including double circuit for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts based on an issued environment act licence and increased scope for Long Spruce and Henday switchyard additions and breaker replacements at existing stations. Project in-service date deferred nine months from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 191.4	$ 63.5	$ 46.2	$ 37.7	$ 8.5	$ -	$ -
Increase (Decrease)	69.0	(5.0)	29.4	14.0	28.2	4.7	-
Revised Forecast	$ 260.2	$ 58.4	$ 75.5	$ 51.7	$ 36.7	$ 4.7	$ -

Bipole III - Community Development Initiative

Description:
Establishment of an obligation for a Community Development Initiative to provide benefits to First Nations, Community Councils, rural Municipalities and incorporated Towns and Villages within the vicinity of the Bipole III Project.

Justification:
Manitoba Hydro is responding to community feedback seeking longer term benefits for communities in proximity to high voltage transmission facilities. These funds will be available for community development projects that benefit a broad segment of eligible communities.

In-Service Date:
July 2018

Revision:
Net Present Value calculation increased due to the nine month in-service deferral from October 2017.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 60.8	$ 2.2	$ 2.0	$ 1.8	$ 0.9	$ -	$ -
Increase (Decrease)	1.2	0.1	(0.0)	0.0	0.7	0.5	-
Revised Forecast	$ 62.0	$ 2.3	$ 2.0	$ 1.8	$ 1.6	$ 0.5	$ -

Riel 230/500kV Station

Description:
Conduct environmental impact assessment and obtain licensing necessary for the Riel 230/500kV station. Design and construct a 230/500kV station at the Riel site including the installation of a 230kV bus with a maximum of five Bays, the installation of a 500kV ring bus, the installation of a 230/500kV 1200MVA transformer bank using two 230kV and one 500kV breaker, and the installation of 500kV line reactors with relocating of a reactor phase from Dorsey. Install a second reactor phase from Dorsey as a spare at Riel after the Riel reactors are in-service and salvage the third reactor phase at Dorsey. Sectionalize two 230kV transmission lines R32V and R33V into Riel station using eight 230kV breakers and associated equipment resulting in two Riel-Ridgeway and two Riel-St. Vital transmission lines. Sectionalize 500kV transmission line D602F into Riel station using two 500kV breakers and associated equipment resulting in Dorsey-Riel and Riel-Forbes 500kV circuits.

Justification:
The sectionalization of the 500kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.

In-Service Date:
October 2014

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 329.9	$ 40.8	$ 0.7	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(4.4)	4.9	-	-	-	-
Revised Forecast	$ 329.9	$ 36.4	$ 5.6	$ -	$ -	$ -	$ -

Manitoba-Minnesota New 500kV Transmission Line

Description:
Design, construct and commission a 235km 500kV AC single-circuit transmission line from Dorsey Station to the US border. Design and install one 500kV breaker, one 150MVAr 500kV shunt reactor, one double-wye ungrounded 46kV 73.4MVAr shunt capacitor bank and associated communications and protection at Dorsey. Design and install two 500kV breakers, one 230kV breaker, two double-wye ungrounded 46kV 73.4MVAr shunt capacitor banks, a 1 200MVA 230/500kV autotransformer and associated communications and protection at Riel. Acquire property for right-of-way, conduct environmental impact assessment, conduct community consultations, obtain licensing and perform environmental monitoring for all new facilities. Design, procure and install a new 300MVA phase shifter at Glenboro Station and re-align the transmission lines at the Glenboro Station to accommodate the new transformer.

Justification:
Power sale term sheets have been negotiated with Minnesota Power (250MW) and Wisconsin Public Service (300MW). The existing tie line capacity is insufficient to accommodate the additional sales and therefore a new export line is needed. The proposed transmission facilities will increase the Manitoba to U.S. transfer capability for both export and import purposes.

In-Service Date:
May 2020

Revision:
Cost flow revision and in-service date deferred seven months from October 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 350.3	$ 3.8	$ 29.7	$ 101.1	$ 58.7	$ 63.5	$ 91.8
Increase (Decrease)	-	3.2	3.0	(1.5)	0.7	2.2	(8.3)
Revised Forecast	$ 350.3	$ 7.0	$ 32.7	$ 99.6	$ 59.5	$ 65.7	$ 83.5

Firm Import Upgrades

Description:
Reconductor and resag transmission lines SC25, WT34, and SM26, and replace risers and/or current transformers for stations at Whiteshell, Ridgeway, Transcona, and Parkdale.

Justification:
This project will increase to 100MW Manitoba Hydro's firm import capability from Ontario. Increasing the transmission capability will permit greater volume of energy imports during periods when additional energy may be required.

In-Service Date:
Cancelled.

Revision:
Project cancelled. Since the project was initially approved in 2008 and additional funding approved in 2011, market and corporate conditions have changed, and this import upgrade is no longer a priority considering the capital needs for major projects which must be undertaken. This project is not required for reliability or safety, and its cancellation will not negatively impact financial projections.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 19.9	$ 10.8	$ 8.9	$ -	$ -	$ -	$ -
Increase (Decrease)	(19.9)	(10.8)	(8.9)	-	-	-	-
Revised Forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce electricity consumption in Manitoba.

Justification:
The electric Demand Side Management plan is cost effective as a resource option and is included in Manitoba Hydro's Power Resource Plan (PRP). The DSM plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information and designed to aggressively pursue cost-effective market-achievable savings. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under the interim standard that continues to permit rate-regulated accounting.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 25.3	$ 24.6	$ 23.9	$ 22.6	$ 21.7	$ 266.9
Increase (Decrease)		26.5	34.6	52.7	61.3	72.0	555.0
Revised Forecast	NA	$ 51.8	$ 59.2	$ 76.6	$ 83.9	$ 93.7	$ 821.9

MAJOR CAPITAL:

GENERATION OPERATIONS:

Pine Falls Units 1-4 Major Overhauls

Description:
Rehabilitation, replacement of and addition to various equipment such as generator re-wind, stator radial keys, breakers, cooling radiators, instrument transformers, unit control & monitoring systems, excitation system upgrades, governor upgrades, meter upgrades, and powerhouse crane refurbishment. Replace unit 1-4 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials. Conduct a model test and up-rate study.

Justification:
Assessment of the mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
September 2019

Revision:
Cost flow revision and in-service date deferred five months from April 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 142.2	$ 8.0	$ 5.0	$ 21.9	$ 30.2	$ 27.0	$ 16.0
Increase (Decrease)	-	(0.8)	(4.3)	(7.9)	(3.8)	2.6	24.9
Revised Forecast	$ 142.2	$ 7.2	$ 0.7	$ 14.0	$ 26.4	$ 29.6	$ 40.9

Jenpeg Overhaul Program

Description:
Major overhaul of all six generating units to inspect, repair, modify, and replace components of the turbine/ generator. Areas of concern include journal bearings, thrust bearings, turbine seals, servo motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, and auxiliary systems.

Justification:
A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

In-Service Date:
December 2031.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9

Slave Falls Major Overhauls

Description:
Perform major overhaul for all eight units at Slave Falls generating station, including spillway improvements/ replacements, excitation upgrades, the addition of a Unit Control and Monitoring System (UCMS) Framework, access road upgrades, and a new walkway across the spillway.

Justification:
Many safety, reliability, environmental, efficiency, operational & dam safety issues have been identified relating to the Slave Falls infrastructure. Extensive repairs, modifications and/or replacements will be required to ensure the serviceability of the plant and spillway infrastructure. Economics of this work may suggest that a new spillway be constructed to replace existing spill infrastructure. Current operating procedures include ice load reduction activites at the spilling structures to ensure structural stability. A dam safety concern has been identified with respect to the minimal remote spilling capability at Slave Falls.

In-Service Date:
September 2027.

Revision:
In-service date deferred six years from September 2021.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 126.1	$ 0.2	$ 0.9	$ 5.3	$ 26.6	$ 30.3	$ 62.9
Increase (Decrease)	-	(0.2)	(0.9)	(5.3)	(26.6)	(30.3)	63.3
Revised Forecast	$ 126.1	$ -	$ -	$ -	$ -	$ -	$ 126.1

Water Licenses & Renewals

Description:
Conduct hydraulic studies, geotechnical assessments, property status and severance line determinations, mapping, license documentation, environmental reviews, and community informational sessions necessary to secure license finalization and/or renewals for the Corporation's hydraulic plants.

Justification:
All hydraulic generating facilities must be authorized under water power licenses and these licenses need to be clearly in force to significantly reduce risk exposure, maintain operating flexibility, maximize export revenues, and contribute to financial strength.

In-Service Date:
Various

Revision:
This item is made up of numerous License Finalizations, Renewals and other programs included to proactively protect the environment and contribute to the corporation's sustainable development principles. It is considered an on-going program cost therefore the budget is now included in Generation Operations Base Target.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 7.0	$ 7.0	$ 6.5	$ 2.4	$ -	$ -
Increase (Decrease)	NA	(7.0)	(7.0)	(6.5)	(2.4)	-	-
Revised Forecast	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Pointe du Bois GS Rehabilitation

Description:
Implement safety upgrades for the Pointe du Bois generating station including fire protection, mechanical hazards, electrical hazards, operational hazards, trips and fall hazards, and various other safety upgrades. Additionally, implement turbine and generator, equipment and civil rehabilitation and upgrades.

Justification:
To provide a high level of health and safety upgrades as well as improved reliability and control, along with a reduction in potential environmental impacts from catastrophic events such as fire or flooding. The plan provides the most economical solution to operate the generating station for an additional twenty years.

In-Service Date:
March 2021

Revision:
Cost flow revision and advanced in-service date five years and four months from July 2026.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 182.9	$ 10.3	$ 15.3	$ 21.7	$ 19.5	$ 20.4	$ 81.5
Increase (Decrease)	-	(0.2)	0.1	25.3	30.5	4.8	(60.5)
Revised Forecast	$ 182.9	$ 10.1	$ 15.4	$ 47.0	$ 50.0	$ 25.2	$ 21.0

Great Falls Unit 4 Overhaul

Description:
Major overhaul to generating Unit 4 including generator rewind, turbine re-runnering, new water passage embedded components, one 3-phase unit transformer, and modernization of components.

Justification:
The re-runnering and major overhaul will provide an opportunity to upgrade/modernize the unit while taking advantage of an already planned outage for the intake gates. The re-runnering will add both capacity and efficiency. The existing transformer is in poor condition and water passage components are starting to fail. The overhaul will increase reliability and extend the asset life by 40 to 50 years.

In-Service Date:
August 2015.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 53.6	$ 16.5	$ 11.9	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.8)	2.3	-	-	-	-
Revised Forecast	$ 53.6	$ 15.8	$ 14.2	$ -	$ -	$ -	$ -

Brandon Units 6 & 7 "C" Overhaul Program

Description:
Perform C inspections/overhauls of the Brandon gas turbines Unit 6 & 7 when each of them acquires 24,000 Equivalent Operating Hours (EOH).

Justification:
The reliability of the hot gas path components cannot be predicted after 24,000 EOH. Failure of hot gas path parts could lead to significant collateral damage and an extended forced outage of the units.

In-Service Date:
March 2024.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4

TRANSMISSION:

Rockwood East 230/115kV Station

Description:
Design and construct a new 230/115kV Rockwood East Station adjacent to 230kV circuits A3R (Ashern-Rosser) and S65R (Silver-Rosser) including associated equipment, protection, control and communication systems. Sectionalize and extend 230kV and 115kV transmission lines as required and provide communication and protection upgrades.

Justification:
Construction of the Rockwood East Station with three 115kV line terminations would alleviate the overload scenarios for Rosser 230/115kV Banks 2 and 4 and for 115kV circuits CR4 or CR2 between Rosser and Parkdale Stations. It would also increase the 115kV capacity in the Rosser/Parkdale/Selkirk area. The existing Parkdale 115/66kV Station switchyard has very limited opportunity for adding new capacity due to the station's poor condition and limited space.

In-Service Date:
November 2015.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 53.3	$ 29.1	$ 8.6	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(2.5)	2.5	-	-	-	-
Revised Forecast	$ 53.3	$ 26.6	$ 11.1	$ -	$ -	$ -	$ -

Lake Winnipeg East System Improvements

Description:
Build a new 115/66kV Manigotagan Corner Station complete with two 6OMVA transformers, a new 65km, 115kV transmission line from Pine Falls Station to Manigotagan Corner Station and the associated terminations and communications.

Justification:
Pine Falls Station currently operates over firm transformation during winter peak. The absence of firm transformation would cause customer outages in the Lake Winnipeg East area during a Pine Falls transformer outage. The outage would last greater than a week until a spare transformer could be brought in from Winnipeg and connected. A transformer outage would affect more than 1,300 permanent customers and more than 13,000 seasonal (summer) customers. Deferral will place customers at risk of no supply. The new 115/66kV Manigotagan Corner Station and Pine Falls – Manigotagan Corner 115kV Transmission Line will provide firm capacity for area load for the next 20 years, as well as enable the Bloodvein SVC to control effectively the voltage at Bloodvein, Little Grand Rapids, Beren's River and Poplar River for the next 20 years. It also reduces the loading on Pine Falls 115/66kV Station, thereby accommodating load growth in the Victoria Beach, Grand Beach and Bissett areas.

In-Service Date:
October 2016

Revision:
Cost flow revision and in-service date deferred eleven months from November 2015.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 64.6	$ 30.0	$ 17.2	$ 0.0	$ -	$ -	$ -
Increase (Decrease)	-	(15.7)	18.6	8.2	-	-	-
Revised Forecast	$ 64.6	$ 14.2	$ 35.8	$ 8.2	$ -	$ -	$ -

Letellier - St. Vital 230kV Transmission

Description:
Design and construct a new 230kV line from Letellier Station to St. Vital Station including associated terminations and communications. Includes environmental licensing and monitoring, and property rights acquisition.

Justification:
The supply to Letellier Station must be improved in order to overcome the contingency loading and low voltage problems in the south central area of Manitoba caused by load growth, as well as to maintain export levels on the 230kV Tie Line L20D (Letellier to Drayton) at these increased loads.

In-Service Date:
July 2017

Revision:
Cost flow revision and an eleven month deferral from August 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 59.0	$ 3.0	$ 34.9	$ 18.1	$ 1.6	$ -	$ -
Increase (Decrease)	-	(1.7)	(31.2)	18.9	12.3	1.6	-
Revised Forecast	$ 59.0	$ 1.3	$ 3.7	$ 37.0	$ 13.9	$ 1.6	$ -

Transmission Line Upgrades for NERC Alert

Description:
This project consists of a nine year program to upgrade over 1000 transmission line spans to meet CSA Standards for line clearance. A priority listing of the transmission lines and spans requiring mitigation will be developed based on assessment work considering operational and safety risks specific to each line/span.

Justification:
This program addresses discrepancies between the design ratings and actual field ratings of transmission lines thereby ensuring continued reliability and operation of the electrical system as well as mitigating risks to public safety due to insufficient line clearance.

In-Service Date:
March 2023.

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 151.3	$ 1.1	$ 8.9	$ 9.0	$ 9.1	$ 23.7	$ 99.5
Increase (Decrease)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.4)	1.1
Revised Forecast	$ 151.3	$ 1.0	$ 8.6	$ 8.8	$ 8.9	$ 23.3	$ 100.6

HVDC Dorsey Synchronous Condenser Refurbishment

Description:
For all nine (9) Synchronous Condensers at Dorsey, project includes major mechanical refurbishment consisting of re-wedging the stator, refurishment of bearings, rotor, and poles, and replacement of protection and control cubicles, Motor Control Center (MCC), excitation system and cables. Other work includes replacing the H2/CO2 ventilation and detection systems (except SC9Y), vibration monitoring, pony motor brushgear, and liquid mixing valves.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
October 2021.

Revision:
Cost flow revision and in-service date deferred two years from October 2019.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 73.3	$ 7.9	$ 8.9	$ 8.5	$ 5.9	$ 3.4	$ 0.8
Increase (Decrease)	-	0.8	(0.4)	(5.8)	(0.7)	(1.2)	6.6
Revised Forecast	$ 73.3	$ 8.7	$ 8.5	$ 2.7	$ 5.2	$ 2.2	$ 7.3

Dorsey 230kV Phase II Zone Building

Description:
Construction and equipping of two new zone buildings and refurbishing of the existing relay building and equipment. This project also includes installing and replacing various pieces of equipment and modifications to the switchyard.

Justification:
Construction of two new hardened relay buildings plus the hardening and conversion of the existing relay building is the most cost effective and practical option. This approach segregates the 230kV switchyard into three sections, providing for the majority of the 230kV switchyard to remain operational following the loss of a zone building. This meets Manitoba Hydro’s system restoration criteria.

In-Service Date:
Cancelled

Revision:
Item cancelled. The Phase I improvements to Dorsey’s 230kV Relay Building have significantly reduced the risk of catastrophic failure caused by severe weather and/or fire. The building has been fortified to withstand an F3 category tornado and the implemented fire mitigation measures have reduced the probability of a major fire with the Relay Building by greater than 200 times. These enhancements combined with the future addition of Bipole III have reduced the risks sufficiently to eliminate the need for Phase II.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ -	$ -	$ 0.4	$ 16.5	$ 33.2	$ 13.3
Increase (Decrease)	-	-	-	(0.4)	(16.5)	(33.2)	(13.3)
Revised Forecast	NA	$ -	$ -	$ -	$ -	$ -	$ -

Bipole 2 Thyristor Valve Replacement

Description:
Removal of the existing eight (8) thyristor valve groups and their controls, and replace them with eight new de-ionized water cooled HVDC thyristor valve groups and controls.

Justification:
The Bipole 2 thyristor valves and controls are nearing the end of their useful life and require replacement. Replacing the existing thyristor valve groups and controls with new ones will result in reducing the probability of forced outages. This will result in a significant decrease in failures, reduce maintenance requirements, and generally improved reliability for Bipole 2.

In-Service Date:
October 2023

Revision:
Cost flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 233.7	$ -	$ -	$ -	$ 2.1	$ 13.3	$ 218.3
Increase (Decrease)	-	-	-	-	-	(0.1)	0.1
Revised Forecast	$ 233.7	$ -	$ -	$ -	$ 2.1	$ 13.2	$ 218.4

CUSTOMER SERVICE & DISTRIBUTION:

New Madison Station - 115/24kV Station

Description:
Build a new 115/24kV St. James Station, new and upgraded feeders, and conversion of St. James, Ness, Berry and King Edward station feeders from 4kV to 24kV. Install 1.5km of new 115kV cable from St. James Station and protection upgrades required at Rosser, Inkster Sherbrook, Mohawk and La Verendrye stations.

Justification:
This project is required to ensure firm supply and a reliable system in the St. James area.

In-Service Date:
March 2017.

Revision:
The installation of 1.5km of 115kV cable from St. James Station to Madison Station is now required because tapping off existing infrastructure in the area is not viable. The contract bid price for the construction of the station and the internal labour to support the contract was higher than previously estimated. The protection upgrades at other stations was not included in previous estimates. The multi in-service date is deferred by twelve months to March 2017 without changing the Madison Station in-service date of March 2016.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 69.6	$ 20.0	$ 25.6	$ 16.1	$ 1.3	$ -	$ -
Increase (Decrease)	17.5	12.6	8.0	(3.3)	(1.3)	-	-
Revised Forecast	$ 87.1	$ 32.6	$ 33.6	$ 12.8	$ -	$ -	$ -

St. Vital Station - 115/24kV Station

Description:
Install a 3-bank 115/24kV station complete with nine feeder positions and protection to replace the existing 24kV distribution at St. Vital Station.

Justification:
The project addresses the equipment rating concerns currently mitigated by station operating restrictions and customer-driven demand for electricity in the area, as well as restoring reliable station contingency plans.

In-Service Date:
December 2018.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 51.3	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9	$ -
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 51.3	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9	$ -

Dawson Road Station - 115/24kV Station

Description:
Install a 2-bank 115kV/24kV station complete with six feeder positions and two capacitor banks to replace existing 24kV distribution equipment at Dawson Road Station.

Justification:
Justification is based on fulfilling customer-driven demand for electricity in the area as well as providing a reliable supply to customers in contingency situations.

In-Service Date:
December 2019.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 51.8	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 20.0	$ 9.3
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 51.8	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 20.0	$ 9.3

Burrows New 66/12kV Station

Description:
Build a new two bank 66kV/12kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations.

Justification:
Most of the equipment in this part of Winnipeg has been in service for 77 years. Alfred Station (which supplies Charles Station) lacks access to a satisfactory alternate supply in the event of a 12kV interruption out of Rover Station. Remedial action was recommended for both stations in the Due Diligence Report. It indicated the 4kV switchgear lineups at Alfred and Charles Stations lack arc-resistance and at Alfred Station are sometimes underrated for the available fault current during normal operating conditions. It also had concerns that neither station has an appropriate battery room, all station transformers have patched leaks, they contain asbestos materials, and that spare parts are in short supply.

In-Service Date:
March 2015.

Revision:
Cash flow revision only.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ 54.7	$ 5.1	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(2.7)	-	-	-	-	-
Revised Forecast	$ 54.7	$ 2.4	$ -	$ -	$ -	$ -	$ -

New Adelaide Station 66/12kV

Description:
Construct a new Adelaide Station with 3 x 66-12kV, 30 MVA transformers and three line-ups of switchgear for twenty-three feeder positions. Install a control building for 12kV switchgear, communication, control and protection equipment. Install a 66kV GIS building/equipment for station supply terminations. Install 2 x 3km lengths of 66kV cable through new ductline to extend 66 kV line W6 to terminate at new station. Install new distribution ductline egresses from new station to connect to existing ductline system in downtown area.

Justification:
Constructing the new Adelaide Station will allow for the decommissioning of King Station, addressing all concerns with safety and aging infrastructure at King Station. Adelaide Station also provides sufficient area capacity to allow the proposed William Station project to be deferred. Five feeders from the new Adelaide Station will be expressed through new ductline towards the Health Science Centre (HSC) to aid Sherbrook Station in supplying that area. Sherbrook Station does not have capacity to continue to handle load growth around the HSC Complex by itself.

In-Service Date:
October 2023

Revision:
New item.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	62.1	0.7	21.2	22.9	8.8	5.0	3.4
Revised Forecast	$ 62.1	$ 0.7	$ 21.2	$ 22.9	$ 8.8	$ 5.0	$ 3.4

BASE CAPITAL:

ELECTRIC OPERATIONS:

Generation Operations

Description:
These projects are required to provide safe, reliable, efficient supply of power, and to replace plant facilities which are at the end of their useful life. This is comprised of:

GENERATION – Projects relating to upgrading or replacing infrastructure, controls, transformers, breakers, and other equipment at existing generating stations.

GENERATION TOWN SITE SERVICES - Projects required to maintain facilities and provide services to town sites such as Gillam, Grand Rapids and Seven Sisters.

OTHER CAPITAL - Projects relating to upgrading replacing or enhancing domestic water and waste water systems, security systems, office, plant and field equipment replacements; communications; tools and test equipment as well as water licenses & renewals.

Justification:
The generation availability of the older assets has been declining over the last ten years. As Generation Operation's assets age, there is an increase in risk to their availability, which could result in months or years of unit outages and significantly impact the ability to produce power to the transmission system. Enhancements or rehabilitation to the power supply facilities will ensure a safe, reliable and efficient source of energy.

Revision:
Combined Major and Base targets revised through to 2020/21 and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets and Major & Base targets.

Generation Operations Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 94.2	$ 87.7	$ 101.8	$ 63.9	$ 59.6	$ 1 186.4
Increase (Decrease)		4.7	13.9	(30.8)	(8.2)	17.6	699.7
Revised Forecast	NA	$ 98.9	$ 101.6	$ 71.0	$ 55.7	$ 77.2	$ 1 886.1

Generation Operations Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 136.3	$ 127.9	$ 157.1	$ 142.5	$ 137.3	$ 1 513.2
Increase (Decrease)		(4.3)	4.1	(25.1)	(10.5)	(5.3)	727.4
Revised Forecast	NA	$ 132.0	$ 132.0	$ 132.0	$ 132.0	$ 132.0	$ 2 240.6

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF14)
For the Years 2014/15 – 2033/34

Transmission

Description:
The majority of projects consist of additions, improvements and replacement of transmission lines; replacement, development and upgrades to HVDC facilities; replacement, development and upgrades to communication systems; additions and replacement of field maintenance equipment; and station upgrades. This is comprised of:

SYSTEM RELIABILITY – Projects that address the reliability or capacity of the transmission, or communication systems, including system emergencies and regulatory compliance.

HVDC FACILITIES - Projects relating to upgrading or replacing transformers, breakers, smoothing reactors, protection, controls and other equipment at HVDC facilities.

CUSTOMER SERVICE - Projects that address new or existing service extensions to larger customers.

ENVIRONMENTAL - Projects that enhance or restore the environment, mitigate damage or potential damage to the environment or remove/salvage plant.

SAFETY – Projects that address risk to public or employee safety or emergency preparedness.

OTHER- Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
This program ensures the reliability of transmission with respect to load, outages, and import/export requirements; as well as addresses safety issues and provides the necessary support for the operation of the HVDC, transmission and communication systems.

Revision:
Combined Major and Base targets revised through to 2020/21 and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets and Major & Base targets.

Transmission Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 114.9	$ 126.1	$ 112.0	$ 70.3	$ 65.6	$ 1 305.3
Increase (Decrease)		(41.8)	(68.8)	(43.7)	24.5	19.2	768.6
Revised Forecast	NA	$ 73.2	$ 57.3	$ 68.3	$ 94.8	$ 84.8	$ 2 073.9

Transmission Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 185.9	$ 204.5	$ 148.0	$ 105.5	$ 139.2	$ 1 637.3
Increase (Decrease)		(60.9)	(79.5)	(23.0)	19.5	(14.2)	763.1
Revised Forecast	NA	$ 125.0	$ 125.0	$ 125.0	$ 125.0	$ 125.0	$ 2 400.3

Customer Service & Distribution

Description:
These projects are required to extend sub-transmission, distribution, and transformation facilities to supply service to residential, farm, commercial and industrial customers, and to replace plant facilities whose useful life has been exceeded. Specific types of expenditures include station and line additions, modifications and rebuilds, bank additions, breaker replacements, defective cable replacement, highway changes, field maintenance equipment, woodpole replacements and ice melting requirements. These costs are spread over many facility locations throughout the Province and are comprised of:

SYSTEM IMPROVEMENTS - Projects relating to additions and modifications to the existing electric distribution network to maintain system reliability and standards of safety, as a result of customer load growth, aging infrastructure and operational standards of performance. Assets and facilities include distribution stations, poles, conductors, transformers, streetlights, cables, duct lines and manholes.

CUSTOMER SERVICE - Projects relating to new or existing service extensions to commercial and residential customers.

NEW STATIONS - Projects relating to station development requirements in both Winnipeg and rural Manitoba to address capacity limitations.

OTHER CAPITAL - Projects relating to VHF radio replacements and field maintenance equipment.

Justification:
The residential, farm, commercial and industrial loads are expected to grow at an average rate in excess of 1.5% per annum and will require a program of additions to the system to accommodate these anticipated loads. As the distribution assets are approaching the end of their designated lifespan a four year program has been established to replace critical infrastructure.

Revision:
Combined Major and Base targets revised through to 2020/21 and increased thereafter to consider increased requirements for aging infrastructure replacement based on asset condition assessments.

The tables below show the changes in Base Targets with and without Major Projects > $50M.

Customer Service and Distribution Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 207.6	$ 211.8	$ 229.2	$ 143.8	$ 134.3	$ 3 709.4
Increase (Decrease)		(10.6)	(29.1)	(19.6)	16.9	38.8	140.8
Revised Forecast	NA	$ 197.0	$ 182.6	$ 209.6	$ 160.7	$ 173.0	$ 3 850.2

Customer Service and Distribution Major & Base Target

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 235.5	$ 240.9	$ 268.3	$ 181.7	$ 162.2	$ 3 718.6
Increase (Decrease)		-	-	-	24.3	43.8	144.2
Revised Forecast	NA	$ 235.5	$ 240.9	$ 268.3	$ 206.0	$ 206.0	$ 3 862.9

Customer Care & Energy Conservation

Description:
This program covers the additions and replacements of meters, transformers and related equipment and is comprised of:

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

OTHER– Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Increase due to the addition of meter exchanges and sampling which will be reclassified from operating expenses to capital upon adoption of IFRS in 2015/16.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 3.1	$ 3.2	$ 3.3	$ 3.3	$ 3.4	$ 59.8
Increase (Decrease)		-	0.8	0.8	0.8	0.8	1.7
Revised Forecast	NA	$ 3.2	$ 4.0	$ 4.1	$ 4.1	$ 4.2	$ 61.5

Human Resources & Corporate Services

Description:
The program consists of information technology hardware and software upgrades and application development, corporate building refurbishments and new building programs, fleet vehicle refurbishment and replacement as well as projects associated with property easements, and acquisition of equipment for the training centre, print shop, fleet, materials management, and facilities.

CORPORATE BUILDINGS - Projects associated with the cyclical acquisition, and/or replacement of corporate administrative facilities throughout the Province.

FLEET ACQUISITIONS - Projects associated with the cyclical procurement, refurbishment and/or replacement of corporate fleet vehicles and equipment.

INFORMATION TECHNOLOGY HARDWARE / SOFTWARE - Projects associated with the purchase and installation of hardware and software upgrades, personal computers, networks and cabling.

INFORMATION APPLICATION DEVELOPMENT - Projects associated with installing, developing or upgrading computer applications for the corporation.

OTHER – Projects associated primarily with property easements and equipment for the training centre, print shop, fleet, materials management and facilities.

Justification:
To provide safe, efficient and productive; corporate buildings, fleet vehicles and equipment. Also to enhance computer systems throughout the corporation to achieve ongoing improvement in productivity and reliability.

Revision:
Base targets revised through to 2020/21 including new district office buildings and completion of Enterprise Asset Management project and escalated at 2% thereafter to consider increased requirements for aging infrastructure replacement.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 75.7	$ 54.8	$ 54.8	$ 34.4	$ 32.1	$ 638.7
Increase (Decrease)		(0.7)	20.2	0.2	20.6	22.9	294.9
Revised Forecast	NA	$ 75.0	$ 75.0	$ 55.0	$ 55.0	$ 55.0	$ 933.6

Finance & Regulatory

Description:
This program is primarily for meter purchases (for load research monitoring), and handheld devices associated with the load research function. Other items include the purchase of additional servers and other information technology related equipment and specialized software.

Justification:
The load research program supports the development of customer rates and also supports Power Smart initiatives in terms of planning and support.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8

GAS OPERATIONS:

Customer Service & Distribution

Description:
This program consists of projects required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines. This is comprised of:

SYSTEM IMPROVEMENTS – Projects relating to system modifications and betterment. Significant work includes capacity upgrades, system integrity upgrades, regulator station upgrades and cathodic protection upgrades.

NEW BUSINESS - Projects for installing new services and distribution mains for both commercial and residential customers.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

Revision:
None.

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 21.2	$ 501.7
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast	NA	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 21.2	$ 501.7

Customer Care & Energy Conservation

Description:
This program consists primarily of costs to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba, as well as meters, transformers and related equipment. This is comprised of:

GAS DEMAND SIDE MANAGEMENT – Projects to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba.

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service. Also required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information and designed to aggressively pursue cost-effective market-achievable savings. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under the interim standard that continues to permit rate-regulated accounting.

Customer Care and Energy Conservation

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 5.0	$ 5.1	$ 5.2	$ 5.3	$ 5.4	$ 95.0
Increase (Decrease)		(1.5)	0.3	(0.6)	(0.6)	(0.6)	(11.1)
Revised Forecast	NA	$ 3.4	$ 5.4	$ 4.6	$ 4.7	$ 4.8	$ 84.0

Gas Demand Side Management

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 8.5	$ 7.2	$ 6.9	$ 4.8	$ 3.9	$ 42.1
Increase (Decrease)		1.2	3.2	4.1	4.5	4.8	74.6
Revised Forecast	NA	$ 9.6	$ 10.4	$ 11.0	$ 9.4	$ 8.7	$ 116.7

Manitoba Hydro
Electric Infrastructure Condition Assessment Summary

December 2014

Manitoba Hydro

1. Executive Summary

Manitoba Hydro is one of the largest integrated electricity and natural gas distribution utilities in Canada, serving over 555,000 customers across nearly 650,000 square kilometres. Meeting the needs of its customers requires a vast complex of diverse assets. Though assets are being continually maintained to extend asset life, a significant portion requires reinvestment over the next 20 years due to the current health and age of the assets.

This Electric Infrastructure Condition Assessment Summary report provides an overview of the most significant Manitoba Hydro generation, transmission, high voltage direct current (HVDC) and distribution assets. It consists of current asset conditions, demographics and a 20-year forecast of equipment condition based on current replacement rates and projected replacement or refurbishment work included in the Capital Expenditure Forecast 2013 (CEF13).

Some of these assets are in poorer condition than what is considered acceptable with ages well beyond industry standards and present a significant risk of failure while in-service. In-service failures generally represent a greater risk of customer outages and/or load shedding and are a potential hazard to individuals working in and around these assets as well as to public safety. Some of these assets, such as breakers, generators, wood poles and valve groups, also require significant effort, lead time and capital investment to address their present condition.

The 20-year outlook based on current replacement rates and the CEF13 current capital expenditure forecast indicates a trend toward less asset reliability as more assets slip into the very poor and poor condition categories. This trend is something that must be addressed with additional capital asset sustainment programs or an equivalent means to address this predicted scenario. The 20-year outlook indicates the following items are of most concern:

- Generators
- Generation breakers
- Generation governors
- HVDC smoothing reactors
- HVDC valve groups
- Transmission protection relays
- Distribution wood poles
- Distribution underground cables

Table of Contents

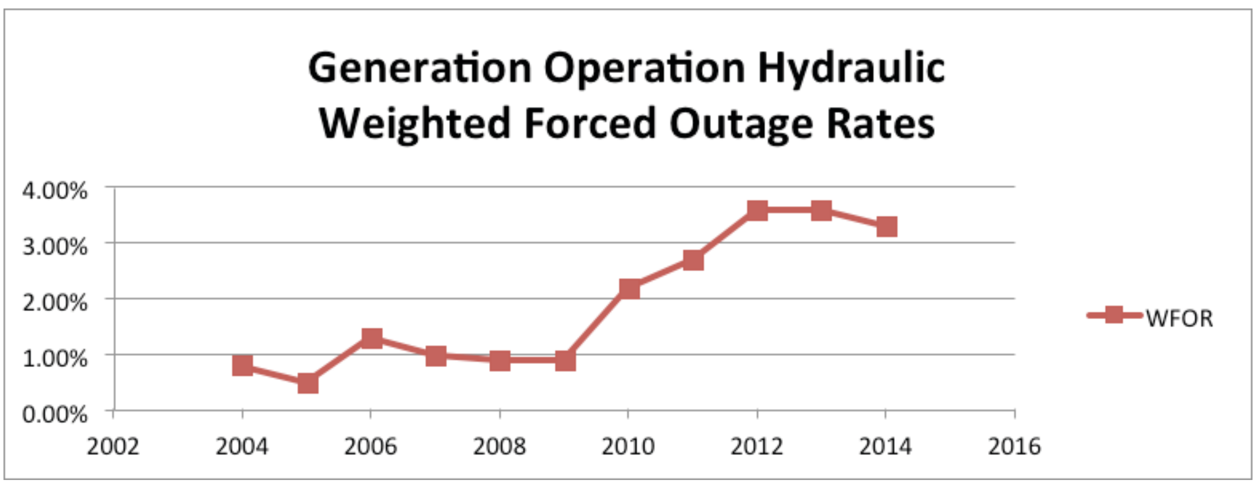
2. Introduction/Background

Manitoba Hydro owns and maintains several million assets throughout Manitoba. This complex electrical system has been developed in key stages over more than 100 years. The assets stretch to all corners of the province with some being in very remote locations without traditional road access.

A considerable amount of Manitoba Hydro's assets were installed prior to 1960 when many of the first generating stations and transmissions systems were built (1911-1950) and when a large portion of the province was electrified (1940-1960). Many of these assets have been well maintained or overhauled and are still in service, providing decades of valuable service to the corporation and its ratepayers. The next mass installation of assets was from 1960 through to 1990 when generating stations were developed on northern Manitoba river systems along with the supporting HVDC system to transport the electricity to customers in the south. Many of these assets are now at or near the end of their design lives and require replacement in the near future to maintain reliability.

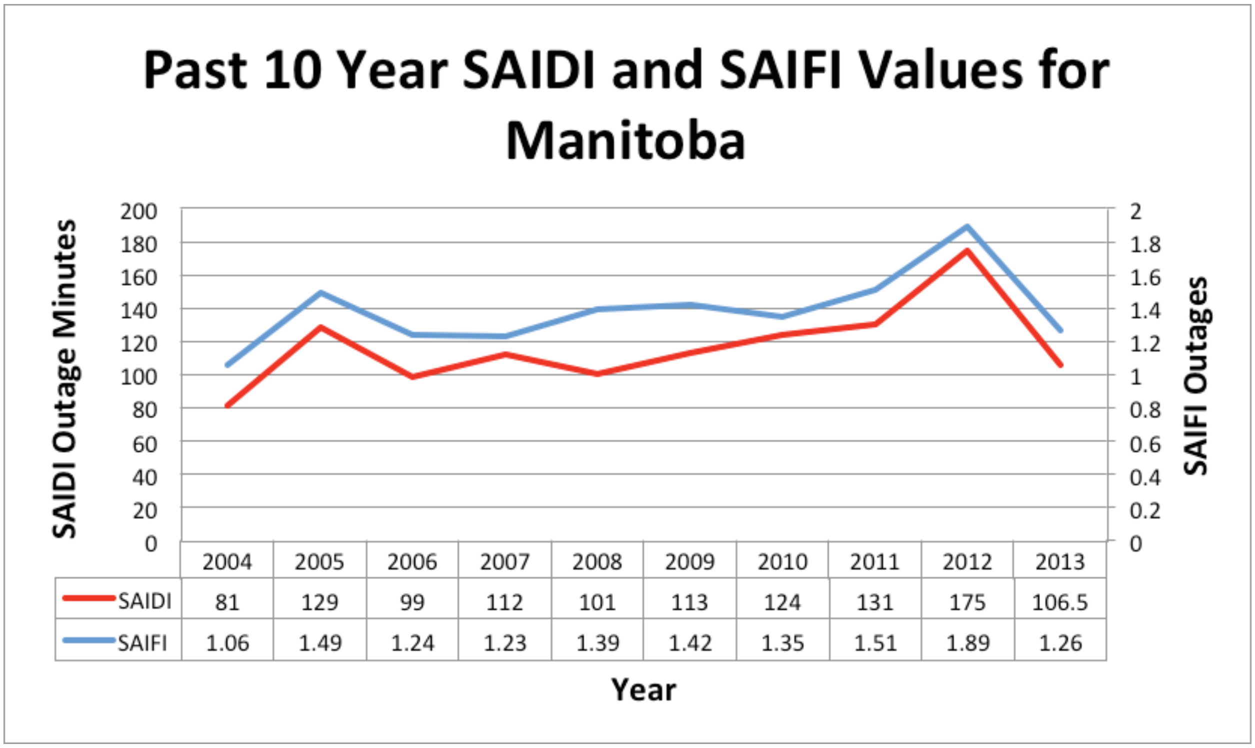
Manitoba Hydro reliability has historically been amongst the best in Canada. However, system reliability performance is beginning to degrade and asset condition is a contributing factor. The following charts are a few key reliability indicators that Manitoba Hydro uses to gauge infrastructure performance.

Generation forced outage rates indicate the amount of time that generation is unavailable due to equipment failures.



***The percentage of service hours that a generating unit is not available due to forced outages as a function of the MCR. MCR is the unit maximum continuous MW rating.**
Weighted Forced Outage Rate (WFOR) = Sum of all units ((Forced Outage Hours Per Unit * MCR Per Unit)) / Sum of all units ((Forced Outage Hours Per Unit + Operating Hours Per Unit) * MCR Per Unit))

SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) values are used throughout the utility industry as a standard for comparison purposes across jurisdictions and is the average outage time and frequency that a customer would experience.



Equipment at the end of its life tends to experience increased failure rates. Many of Manitoba Hydro's assets have been in service since the original system developments. As a result, significant changes to current replacement rates will be required in the future to mitigate the negative impacts of aging infrastructure on our electrical system.

The original cost of these assets is approximately $15 billion with an estimated replacement value that would be many multiples higher due to inflation, increases in commodity prices and other factors. An asset portfolio of this size requires significant reinvestment to ensure that performance and safety standards are achieved.

Objectives of the Electric Asset Health Index Summary Report

This Electric Infrastructure Condition Assessment Summary presents a view of some of the major electrical asset conditions and their demographics. It was completed using industry accepted methodologies for each asset type presented. Asset condition is an important input into the risk management process and the prioritization of capital funding used to maintain a sustainable and reliable electric system for Manitoba.

The 20-year asset condition outlook based on the current capital expenditure forecast indicates a trend toward less asset reliability as more assets slip into the very poor and poor condition. This trend must be addressed with additional capital asset sustainment programs or an equivalent means to address this expected scenario.

3. Methodology

An Asset Health Index (AHI) quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. An AHI should provide a measure of long-term degradation, which is an indicator of the asset's overall health, and should reflect the likelihood that an asset will fail and necessitate a forced replacement or refurbishment. For some asset types, forced replacements can result in substantial costs and extended outages due to delays associated with procuring a replacement asset and with the engineering required to install the replacement (e.g. replacing older breaker or protection relay technologies with newer technologies). Therefore, the AHI provides an important input to the assessment of asset related risks.
Manitoba Hydro used available asset data (such as age, lab tests, equipment vibration and temperature, etc), maintenance and operating experience, and engineering assessments to calculate a condition index for each asset. Availability of various input parameters and data quality differed from asset to asset.

The asset health index methodologies:

- are used to calculate the various ratings for each asset to arrive at the "Asset Health Index" (AHI).
- provide a consistent means of evaluating the condition of individual assets,
- tracks and categorizes the health of a class of equipment,
- assists with asset decision making,
- facilitates planning for future maintenance, replacement and refurbishment.

Across the three business units (Generation Operations, Transmission and Customer Service & Distribution) there are similar asset types, such as breakers, poles, and batteries that are used for the same basic functions. Other asset types, like transformers, seem similar but are utilized in very different operating contexts by each business unit. As a result these assets have different maintenance requirements and life expectancies, and require somewhat different AHI methodologies.

Asset Health Index Summary Graphs

Asset Health Index (AHI) summary graphs show the summary of AHI results in a single picture. The asset class members for each condition rating are charted in colored bar percentages that extend across the grid. The final scoring breakdown provides consistent comparisons across all the various Manitoba Hydro assets.

Scoring breakdown

- **Very poor** = Beyond acceptable level of risk; Action is required over the short term. Asset should be replaced, refurbished or decommissioned soon (Condition Index 0 -1.49)
- **Poor** = Managing risk; Assets may require replacement (approaching or past expected end of life) (Condition Index 1.5- 3.49)
- **Fair** = Long term service without notable measures of degradation (still in its useful part of its life) (Condition Index 3.5 – 4.99)
- **Good** = Midterm service without notable measures of degradation (in the prime of its useful life) (Condition Index 5 – 8.49)
- **Very Good** = Like new operating at expected measure of performance (early in its life) (Condition Index 8.5 -10)

Some assets are replaced based on risk informed economic end of life assessments in conjunction with asset condition score.

4. Individual Asset Condition Assessment and Demographics by Business Unit

The following sections outline, by business unit, the details surrounding each individual asset so that the reader can relate to how the asset is used, how it will degrade, how long it is expected to be in service, and its age and condition demographics at the time this report was prepared.
Asset health indexes continually change based on new asset data as it become available over time and the findings in this report are based on the asset data available prior to reporting.

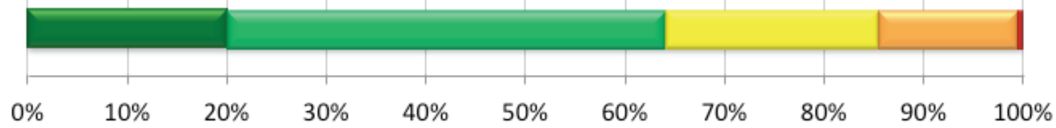
GENERATION OPERATIONS

Generation Operations is responsible for 15 hydroelectric generating stations and two small thermal generating stations with a total combined capacity of approximately 5400 MW.

Generators:

Description:		
A generator is a rotating electrical machine. It is used to convert the mechanical energy of a prime mover to electrical energy. Generators are the source of electrical energy for the bulk electric system. The majority of Manitoba Hydro's electricity is generated in northern Manitoba.		
Degradation: • Insulation break down • Thermal fatigue • Wear of moving parts	**Expected Life:** **(as defined in Appendix A)** 60 years	**Turnover based on Current Replacement Rate:** Approximately every 117 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	32	27.35%
10 to 20	8	6.84%
20 to 30	20	17.09%
30 to 40	16	13.68%
40 to 50	9	7.69%
50 to 60	18	15.38%
60 to 70	0	0.00%
70 to 80	8	6.84%
80 to 90	4	3.42%
> 90	2	1.71%
Grand Total	117	100.00%
Replacement Value	$2 300 M	



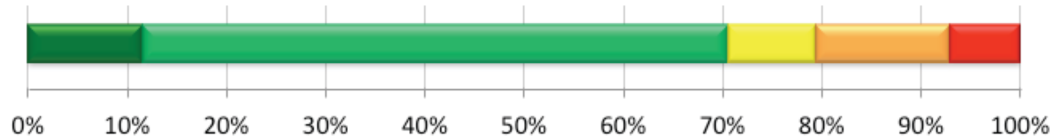
	Asset Quantity	Population Breakdown
Very Good	24	20%
Good	52	44%
Fair	25	21%
Poor	17	14%
Very Poor	1	0%

Very Good Good Fair Poor Very Poor

Hydraulic Turbines:

Description: A hydraulic turbine is a rotating device connected to an electrical generator. It is used to convert the potential energy of stored water to rotating mechanical energy. The expected life of a turbine is long due to the fact that there are many opportunities to refurbish and add years to the life of this asset.		
Degradation: • Cavitation • Wear of moving parts	**Expected Life:** 90-100 years	**Turnover based on Current Replacement Rate:** 84 years Assets are replaced due to end of life as well as economically justified increases to unit output.

Demographics		
AGE (Yrs)	Qty	%
0 to 10	11	9.82%
10 to 20	7	6.25%
20 to 30	16	14.29%
30 to 40	17	15.18%
40 to 50	17	15.18%
50 to 60	8	7.14%
60 to 70	16	14.29%
70 to 80	2	1.79%
80 to 90	8	7.14%
> 90	10	8.93%
Grand Total	112	100.00%
Replacement Value	$2 010M	



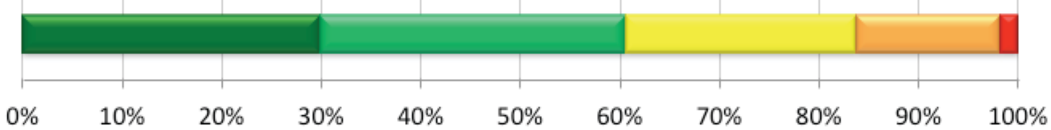
	Asset Quantity	Population Breakdown
Very Good	13	12%
Good	66	59%
Fair	10	9%
Poor	15	13%
Very Poor	8	7%

Very Good Good Fair Poor Very Poor

Exciters:

Description: An exciter is a device used to control the voltage output of an electrical generator. There are different types of exciters used in a utility environment. Older types are typically rotating exciters with many moving parts requiring additional maintenance but increased overall asset longevity compared to the new types which are static analog/digital exciters with fewer repair options and shorter life expectancies.		
Degradation: • Wear of moving parts • Obsolescence	**Expected Life:** 25-90 years[1]	**Turnover based on Current Replacement Rate:** Approximately 117 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	17	14.41%
10 to 20	13	11.02%
20 to 30	18	15.25%
30 to 40	19	16.10%
40 to 50	12	10.17%
50 to 60	6	5.08%
60 to 70	12	10.17%
70 to 80	10	8.47%
80 to 90	8	6.78%
> 90	3	2.54%
Grand Total	117	100.00%
Replacement Value	$220M	



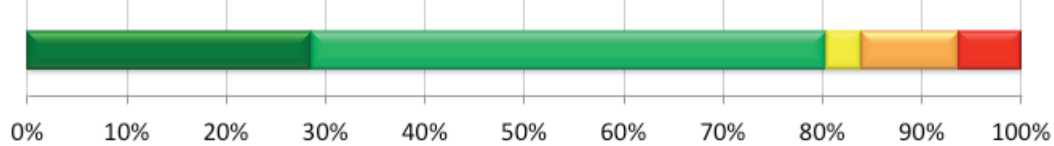
	Asset Quantity	Population Breakdown
Very Good	35	30%
Good	36	31%
Fair	27	23%
Poor	17	15%
Very Poor	2	2%

Very Good Good Fair Poor Very Poor

Governor:

Description: The governor is the machine that controls the mechanical speed of the turbine and ultimately the frequency of the AC power generated. Manitoba Hydro has three types of governors: mechanical, analog and digital. Maintaining the mechanical governors present many opportunities to refurbish and reverse engineer worn parts which extend their life. Newer governors are digital and have much shorter expected lives because of their nature to fail without warning and lack of replacement parts due to obsolescence.		
Degradation: • Wear of moving parts • Obsolescence	**Expected Life:** 25-125 years[2]	**Turnover based on Current Replacement Rate:** Due to a replacement program for electronic governor the turnover has recently been accelerated to approximately 50 years. Previous to that Governors have little history of replacement.

Demographics		
AGE (Yrs)	Qty	%
0 to 10	5	4.46%
10 to 20	15	13.39%
20 to 30	17	15.18%
30 to 40	18	16.07%
40 to 50	7	6.25%
50 to 60	17	15.18%
60 to 70	0	0.00%
70 to 80	21	18.75%
80 to 90	8	7.14%
> 90	4	3.57%
Grand Total	112	100.00%
Replacement Value	$58M	

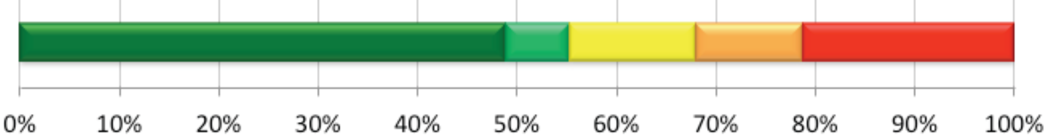


	Asset Quantity	Population Breakdown
Very Good	32	29%
Good	58	52%
Fair	4	4%
Poor	11	10%
Very Poor	7	6%

Battery Banks:

Description: Battery banks are used to provide a source of control power and a back up or emergency source of control power to operate key equipment in the event of a loss of generation or power supply. The battery banks can be used to start a unit and play a key role in allowing the utility to bring the system back online after a serious event or emergency. Battery banks are typically of the lead-acid type similar to car batteries but different voltage level and better quality to allow a longer life span. Generation Operations battery bank condition is not displayed in the forecasted condition as they are replaced to maintain reliability at the end of their expected life.		
Degradation: • Cracks, and physical damage • Cell oxidation • Number and depth of discharges	**Expected Life:** 20 years	**Turnover based on Current Replacement Rate:** Approximately 20 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	16	34.04%
10 to 20	17	36.17%
20 to 30	14	29.79%
Grand Total	47	100.00%
Replacement Value	$6M	



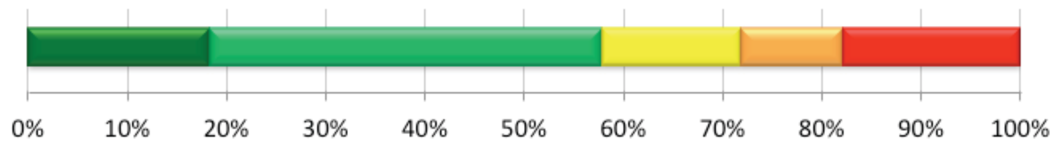
	Asset Quantity	Population Breakdown
Very Good	23	49%
Good	3	6%
Fair	6	13%
Poor	5	11%
Very Poor	10	21%

Very Good Good Fair Poor Very Poor

Breakers:

Description: Breakers are located throughout the generating stations and their corresponding switchyards to allow operators to control the flow of power by opening and closing breakers either locally or remotely from the System Control Center. There are several different types of breaker technology used including sulfur hexafluoride (SF6) (or a mix of gases), air blast and vacuum units.		
Degradation: • Insulation degradation • Mechanical Wear due to normal and fault operations • Obsolescence and depletion of spares • Poor connections	**Expected Life:** 60-65 years	**Turnover based on Current Replacement Rate:** Approximately 129 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	57	14.73%
10 to 20	51	13.18%
20 to 30	53	13.70%
30 to 40	73	18.86%
40 to 50	51	13.18%
50 to 60	72	18.60%
60 to 70	29	7.49%
70 to 80	1	0.26%
Grand Total	387	100.00%
Replacement Value	$220M	



	Asset Quantity	Population Breakdown
Very Good	71	18%
Good	153	40%
Fair	54	14%
Poor	40	10%
Very Poor	69	18%

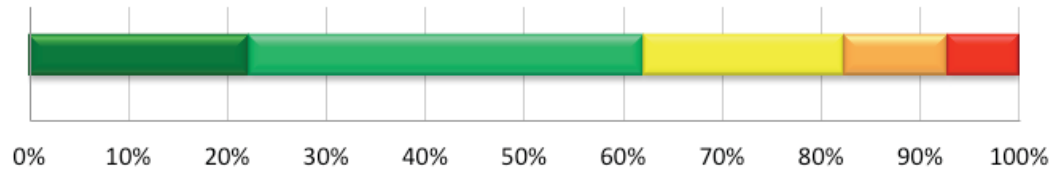
Very Good Good Fair Poor Very Poor

Transformers:

Description:
Power transformers in Generation Operations are typically very large, high value, long lead time, key components that are necessary to convert electrical energy from one voltage to another for the purposes of the delivering bulk electric power from the generators to the transmission system or the generating station for facility use. High voltages are used to minimize line losses over long distances, therefore these types of transformers typically increase the voltage level where power is being generated, move it long distances to areas where the power is to be utilized. Power transformers are oil filled for electrical insulation and cooling purposes.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Insulation degradation or contamination due to heating (loading) or moisture • Corrosion • Mechanical deterioration of tap changer due to operations • Mechanical damage due to through faults or physical impact	40-70 years[3]	Approximately 150 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	23	15.03%
10 to 20	12	7.84%
20 to 30	16	10.46%
30 to 40	16	10.46%
40 to 50	14	9.15%
50 to 60	21	13.73%
60 to 70	28	18.30%
70 to 80	7	4.58%
80 to 90	14	9.15%
> 90	2	1.31%
Grand Total	153	100.00%
Replacement Value	$250M	



	Asset Quantity	Population Breakdown
Very Good	34	22%
Good	61	40%
Fair	31	20%
Poor	16	10%
Very Poor	11	7%

TRANSMISSION

The Transmission Business Unit provides a reliable and safe transmission system for the delivery of electricity to domestic and out-of-province customers; this also includes the High Voltage Direct Current (HVDC) system used to delivery bulk electric power from the large generation base in northern Manitoba to the large load center in southern Manitoba. The AC system and the DC system are significantly different systems maintained by different groups within Manitoba Hydro and therefore the condition assessments were also completed by the appropriate group responsible for each system.

The Manitoba bulk electric system is an interconnected system that is impacted by system expansion as a result of load growth and the need for increased reliability. Asset failures on the transmission system have the potential to dramatically effect reliability, capacity and service but often times are mitigated due to the redundancy built into the bulk electric system. Certain assets are often replaced based not only on condition but other factors such as safety, system development, regulation, obsolescence or economic reasons.

Transmission System Breakers:

<table>
<tr><td colspan="3">Description:
Breakers are strategically located throughout the bulk electric transmission system at voltages ranging from 115 kV to 230 kV and allow utility operators to control the flow of power by opening and closing breakers either locally or remotely from the System Control Center. There are several different types of breaker technology used including SF6 (or a mix of gases), air blast and oil filled units.</td></tr>
<tr><td>Degradation:
Insulation degradation
Mechanical Wear due to normal and fault operations
Obsolescence & depletion of spares
Poor connections</td><td>Expected Life:
60-65 years</td><td>Turnover based on Current Replacement Rate:
149 years[4]</td></tr>
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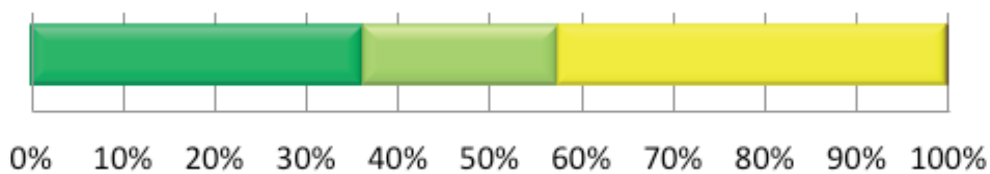
Demographics		
AGE (Yrs)	Qty	%
0 to 10	52	15.16%
10 to 20	43	12.54%
20 to 30	57	16.62%
30 to 40	31	9.04%
40 to 50	97	28.28%
50 to 60	52	15.16%
60 to 70	11	3.21%
Grand Total	343	100.00%
Replacement Value	$176M	

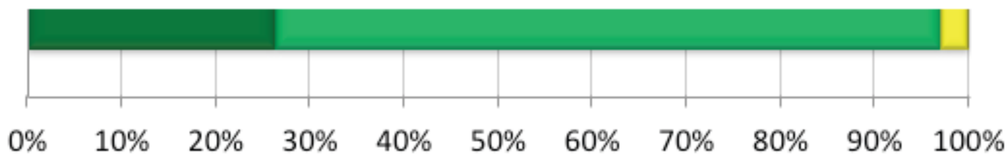


	Asset Quantity	Population Breakdown
Very Good	124	36.15%
Good	73	21.28%
Fair	145	42.27%
Poor	1	0.29%
Very Poor	0	0%

HVDC System Breakers:

Description: Breakers are strategically located throughout the HVDC substation, and 500 yard at voltages ranging from 4kV to 500kV and allow utility operators to control the flow of power by opening and closing breakers either locally or remotely from the System Control Center. There are several different types of breaker technology used including SF6 (or a mix of gases), vacuum, air blast and minimum oil filled units.		
Degradation: • Insulation degradation • Mechanical Wear due to normal and fault operations • Obsolescence & depletion of spares • Poor connections	**Expected Life:** 60-65 years	**Turnover based on Current Replacement Rate:** 58 years[5]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	9	3.49%
10 to 20	133	51.55%
20 to 30	47	18.22%
30 to 40	41	15.89%
40 to 50	28	10.85%
Grand Total	258	100.00%
Replacement Value	$91M[6]	



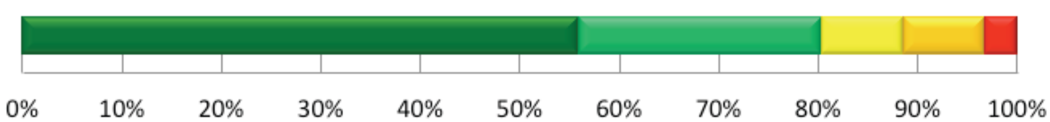
	Asset Quantity	Population Breakdown
Very Good	68	26.36%
Good	183	70.93%
Fair	7	2.71%
Poor	-	0.00%
Very Poor	-	0.00%

Transmission System Battery Banks:

Description:
Battery banks are used to provide a back up or emergency source of control power to operate key substation equipment in the event of a situation where the bulk electric system is not available. Battery banks play a key role in allowing the utility to bring the system back online after a serious event or emergency. Battery banks are typically of the lead-acid type similar to car batteries but different voltage level and better quality to allow a longer life span.

Degradation:	**Expected Life:**	**Turnover based on Current Replacement Rate:**
• Cracks, and physical damage • Cell oxidation • Number & depth of discharges	20 years	15 years[7]

Demographics		
AGE (Yrs)	125 Vdc	%
0 to 10	183	83.18%
10 to 20	31	14.09%
20 to 30	6	2.73%
> 30	0	0.00%
Grand Total	220	100.00%
Replacement Value	$19M	

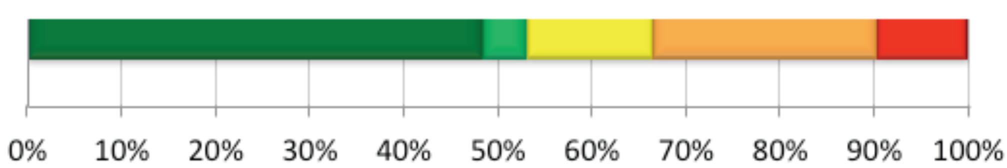


	Asset Quantity	Population Breakdown
Very Good	123	55.9%
Good	54	24.5%
Fair	18	8.2%
Poor	18	8.2%
Very Poor	7	3.2%

HVDC System Battery Banks:

Description: Battery banks are used to provide a back up or emergency source of control power to operate key conversion control equipment and substation equipment in the event of a situation where the bulk electric system is not available. HVDC has various control, and protection battery banks, not just the 125V found in other areas. Battery banks play a key role in allowing the utility to bring the system back online after a serious event or emergency. Battery banks are typically of the lead-acid type similar to car batteries but different voltage level and better quality to allow a longer life span.		
Degradation: • Cracks, and physical damage • Cell oxidation • Number & depth of discharges	**Expected Life:** 20 years	**Turnover based on Current Replacement Rate:** 33 years

Demographics		
AGE (Yrs)	Qty	%
0 to 10	44	41.90%
10 to 20	34	32.38%
20 to 30	27	25.72%
Grand Total	105	100.00%
Replacement Value	$9M	

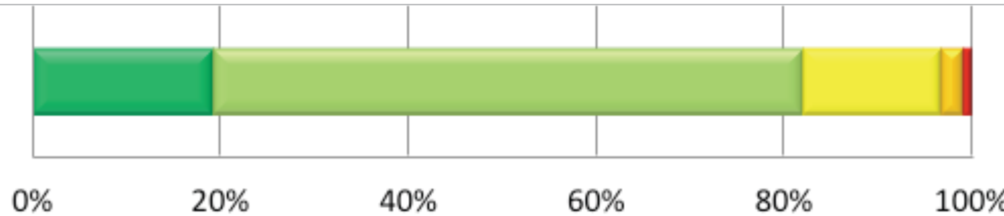


	Asset Quantity	Population Breakdown
Very Good	51	48.57%
Good	5	4.76%
Fair	14	13.33%
Poor	25	23.81%
Very Poor	10	9.52%

Transmission System Transformers:

Description:		
Station Class transformers are necessary to convert electrical energy from one voltage to another for the purposes of delivering bulk electric power over long distances. Tap changers are a component that can be added to a transformer to allow small incremental changes to the voltage ratio based on changing positions of the tap changer. This functionality is used for voltage regulation purposes.		
Degradation: • Insulation degradation or contamination due to heating (loading) or moisture • Corrosion • Mechanical deterioration of tap changer due to operations • Mechanical damage due to through faults or physical impact	**Expected Life:** 40-70 years[8]	**Turnover based on Current Replacement Rate:** 152 years[9]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	18	6.95%
10 to 20	41	15.83%
20 to 30	41	15.83%
30 to 40	38	14.67%
40 to 50	69	26.64%
50 to 60	32	12.36%
60 to 70	20	7.72%
Grand Total	259	100.00%
Replacement Value	$400M	

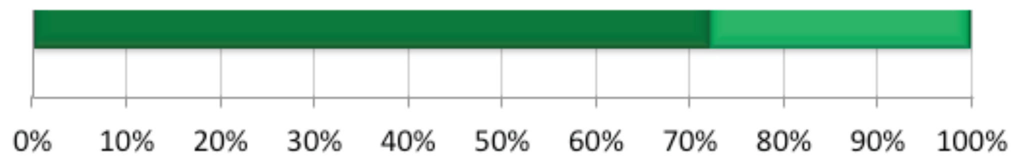


	Asset Quantity	Population Breakdown
Very Good	50	19.31%
Good	163	62.93%
Fair	38	14.67%
Poor	6	2.32%
Very Poor	2	0.77%

HVDC System Transformers:

Description: Transformers are typically very large, high value, long lead time (2-3 years), necessary for exporting power to the U.S., and keeping the HVDC system stable. High voltages are used to minimize line losses over long distances, therefore these types of transformers typically increase the voltage level for transmission and move it long distances to areas where the power is to be utilized. Tap changers are used to make small incremental changes to the voltage ratio. This functionality is used for voltage regulation purposes.		
Degradation: • Insulation degradation or contamination due to heating (loading) or moisture • Corrosion • Mechanical deterioration of tap changer due to operations • Mechanical damage due to through faults or physical impact	**Expected Life:** 40-70 years[10]	**Turnover based on Current Replacement Rate:** 70 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	5	17.24%
10 to 20	1	3.45%
20 to 30	6	20.69%
30 to 40	10	34.48%
40 to 50	7	24.14%
Grand Total	29	100.00%
Replacement Value	$96M	



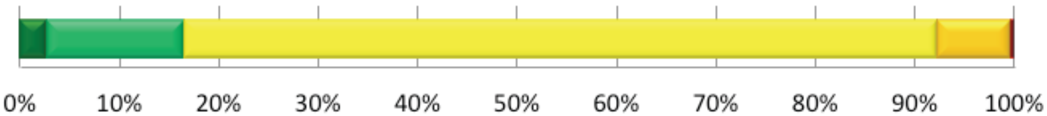
	Asset Quantity	Population Breakdown
Very Good	21	72.41%
Good	8	27.59%
Fair	-	0.00%
Poor	-	0.00%
Very Poor	-	0.00%

Protection Relays:

Description:
Protection relays are critical components used to protect utility assets and ultimately the safety of the public. Protection relays work hand in hand with breakers and are used throughout the utilities electrical system to isolate faults or other inappropriate parameters on the transmission system. Protection relays continuously monitor the electrical system and operate the appropriate breakers to avoid having parts of, or the entire system become unstable and collapse, and to avoid damaging expensive equipment or worse, fires and explosions. Sample represents 80% of total relays on the system.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Obsolescence • Mechanical wear • Electrical component failure	20-50 years[11]	N/A[12]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	155	1.31%
10 to 20	1109	9.40%
20 to 30	1360	11.53%
30 to 40	2649	22.46%
40 to 50	3538	30.00%
50 to 60	2982	25.29%
Grand Total	11793	100.00%
Replacement Value	$312M	

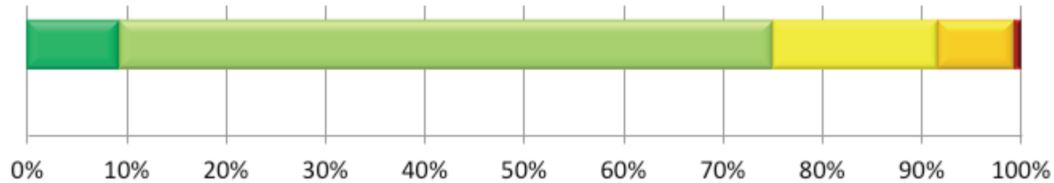


	Population Breakdown	Asset Quantity
Very Good	2.7%	315
Good	13.9%	1634
Fair	75.8%	8940
Poor	7.4%	876
Very Poor	0.2%	28

Transmission System Structures/Grillage:

Description: Structures, grillage and foundations are the means of providing ground clearance for electrical conductors, safely away from the normal activities carried on by people, animals, etc. These structures are typically constructed of steel and form the "backbone" of the bulk electric system.		
Degradation: • Environmental (extreme ice, wind, and fire) • Corrosion (minimal)	**Expected Life:** Minimum 85 years	**Turnover based on Current Replacement Rate:** 285 years[13]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	1050	5.30%
10 to 20	2288	11.56%
20 to 30	990	5.00%
30 to 40	1478	7.47%
40 to 50	6881	34.76%
50 to 60	3178	16.05%
60 to 70	553	2.79%
70 to 80	8	0.04%
80 to 90	2361	11.93%
> 90	1009	5.10%
Grand Total	19796	100.00%
Replacement Value	$4,600M	



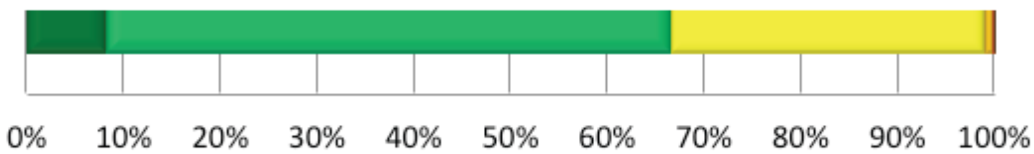
	Asset Quantity	Population Breakdown
Very Good	1846	9.33%
Good	13021	65.78%
Fair	3260	16.47%
Poor	1543	7.79%
Very Poor	126	0.64%

Transmission System Wood Pole Structures:

Description:
Similar in function to steel structures/grillage, wood poles are also used for a variety of reasons including ground clearance for electrical conductors. Transmission wood poles are typically larger in diameter and taller than distribution wood poles. Condition assessment and demographics based on 2012 study.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Environmental (moisture causing shell rot, wood destroying fungi, insect infestation) • Mechanical Damage (contact with snow plows and vehicular traffic)	75 years	255 years[14]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	663	3.63%
10 to 20	1360	7.44%
20 to 30	2032	11.11%
30 to 40	1889	10.33%
40 to 50	7412	40.54%
50 to 60	3293	18.01%
60 to 70	1619	8.85%
70 to 80	0	0.00%
> 80	17	0.09%
Grand Total	18285	100.00%
Replacement Value	$740M	



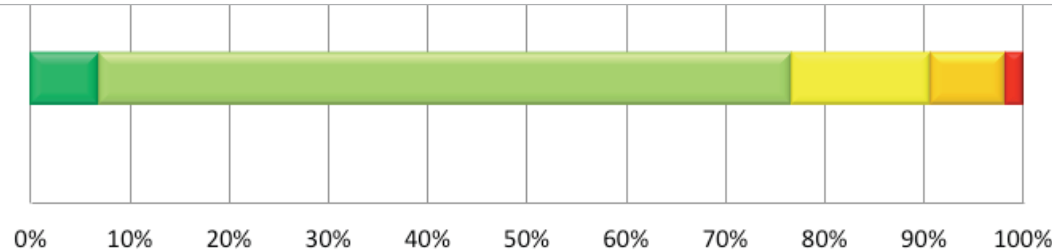
Very Good	1487	8.13%
Good	10700	58.52%
Fair	5904	32.29%
Poor	185	1.01%
Very Poor	9	0.05%

Transmission System Overhead Primary Conductor:

Description:
The overhead primary conductor is the main high voltage, current carrying wire that transmits power from source to load. This wire is usually "ACSR" or Aluminum Conductor Steel Reinforced which consists of a steel core for strength and an outer aluminum current carrying conductor, however there are other types of conductor used as well and it comes in a variety of sizes depending on many factors.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Thermal loading • Vibration • Environmental (extreme ice, wind, and fire) • Corrosion (minimal)	85 years	410 years[15]

Demographics		
AGE (Yrs)	Conductor (km)	%
0 to 10	645	4.51%
10 to 20	1073	7.50%
20 to 30	791	5.53%
30 to 40	1208	8.45%
40 to 50	6289	43.98%
50 to 60	2047	14.31%
60 to 70	898	6.28%
70 to 80	9	0.06%
80 to 90	1094	7.65%
> 90	247	1.73%
Grand Total	14301	100.00%
Replacement Value	1,073M	



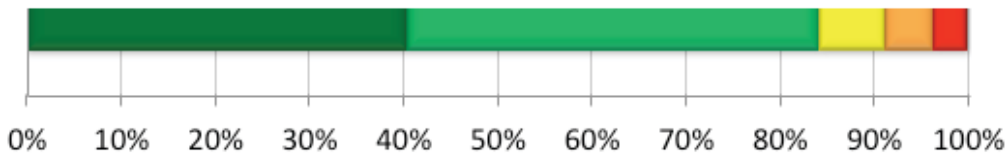
	Conductor (km)	Overall Population
Very Good	984	6.88%
Good	9996	69.89%
Fair	1981	13.85%
Poor	1094	7.65%
Very Poor	247	1.73%

HVDC System Converter Transformers:

Description:
Converter transformers are typically very large, high value, long lead time (3-5 years), key components that are necessary to an HVDC system. The converter transformers step the voltage up or down. The on load tap changer is an essential part of the valve groups' ability to control the voltage and current levels on the DC system. The transformer has much higher insulating values than normal transformers to be able to withstand the stresses from both the AC and DC systems.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Short circuit • Poor connections • Corrosion • Tap changer deterioration • Insulation deterioration • Oil breakdown	40-50 years	73 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	8	14.04%
10 to 20	18	31.57%
20 to 30	2	3.51%
30 to 40	9	15.79%
40 to 50	20	35.09%
Grand Total	57	100.00%
Replacement Value	$349M	

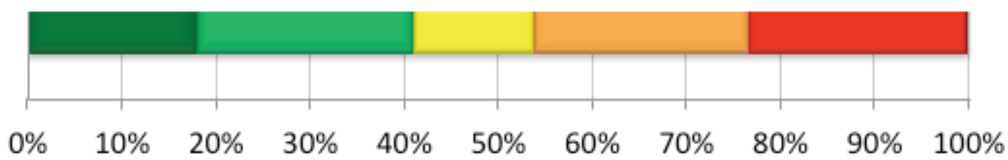


	Asset Quantity	Population Breakdown
Very Good	23	40.35%
Good	25	43.86%
Fair	4	7.02%
Poor	3	5.26%
Very Poor	2	3.51%

HVDC System Valve Groups:

Description: The valve groups are located in the converter buildings. The converter valve is used to convert AC energy to DC energy at the generation end for less expensive transmission over long distances. High voltages are used to minimize line losses over long distances. HVDC uses only two conductors, and shorter less expensive transmission towers for increased savings. Once power reaches its destination the energy is converted to AC for transmission to customers. Large cooling systems keep the thyristors used in the conversion process from overheating and failing to a short circuit. This cooling system has detailed monitoring, and protection to ensure the valve group is maintained below the critical temperatures for thermal runaway of the thyristors.		
Degradation: • Short circuit • Poor connections • Valve cooling deterioration • Controls failure • Thyristor valve control	**Expected Life:** 25 years	**Turnover based on Current Replacement Rate:** 48 years

Demographics		
Age (Yrs)	Qty	%
10 to 20	12	30.77%
20 to 30	12	30.77%
30 to 40	15	38.46%
Grand Total	39	100.00%
Replacement Value	$608M	



	Asset Quantity	Population Breakdown
Very Good	7	17.95%
Good	9	23.08%
Fair	5	12.82%
Poor	9	23.08%
Very Poor	9	23.08%

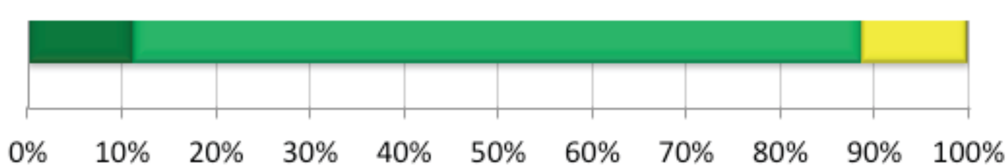
HVDC System Synchronous Condensers:

Description:

The synchronous condenser is located on the AC side of the southern DC station. All the synchronous condensers are electrically driven. The reactive power generated by the synchronous condenser improves system regulation of voltage and the inertia aids in stabilizing frequency. The synchronous condenser is constantly reacting to system conditions either consuming, or adding reactive power to stabilize the power system.

Degradation:	Expected Life:	Turnover based on Current Replacement Rate:
• Short circuit • Unable to supply load • Controls failure • Cooling degradation • Excessive vibration	65 years	65 years[16]

Demographics		
Age (Yrs)	Qty	%
20 to 30	3	33.33%
30 to 40	3	33.33%
40 to 50	3	33.33%
Grand Total	9	100.00%
Replacement Value	$510M	

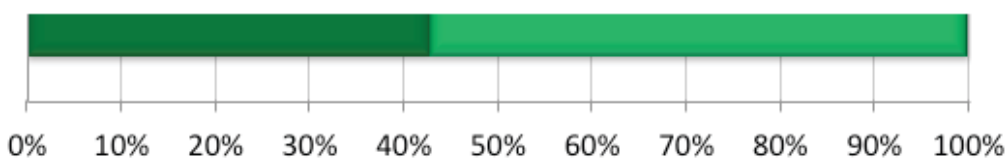


	Asset Quantity	Population Breakdown
Very Good	1	11.11%
Good	7	77.78%
Fair	1	11.11%
Poor	-	0.00%
Very Poor	-	0.00%

HVDC System Shunt Reactors:

Description: The shunt reactors are oil filled devices and are located in the 500KV AC transmission yards. Shunt Reactors are used for extra-high-voltage (EHV) transmission lines to prevent excessive terminal voltage.		
Degradation: • Overheating/Overloads • Insulation deterioration	**Expected Life:** 35 years	**Turnover based on Current Replacement Rate:** 55 years[17]

Demographics		
Age (Yrs)	Qty	%
0 to 10	3	42.86%
30 to 40	4	57.14%
Grand Total	7	42.86%
Replacement Value	$14M	

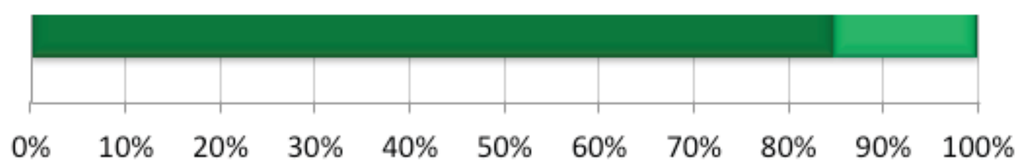


	Asset Quantity	Population Breakdown
Very Good	3	42.86%
Good	4	57.14%
Fair	-	0.00%
Poor	-	0.00%
Very Poor	-	0.00%

HVDC System Smoothing Reactors:

Description:		
This asset is located on the DC side of the system. It is used to minimize harmonics (electrical noise), and help prevent rapid changes in current and excessive electrical current. All smoothing reactors have been changed to air core, from oil filled, to reduce environmental impact, maintenance and repair costs.		
Degradation: • Overheating/Overloads • Insulation deterioration	**Expected Life:** 25 years	**Turnover based on Current Replacement Rate:** 30 years[18]

Demographics		
Age (Yrs)	Qty	%
0 to 10	20	42.86%
Grand Total	20	42.86%
Replacement Value	$60M	



	Asset Quantity	Population Breakdown
Very Good	17	85.00%
Good	3	15.00%
Fair	-	0.00%
Poor	-	0.00%
Very Poor	-	0.00%

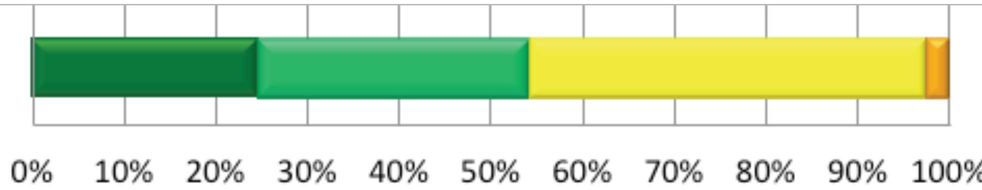
DISTRIBUTION

Distribution is responsible for the delivery of electricity from local sub-stations to the customer throughout the province of Manitoba. Methods of delivery are done by both overhead and underground methods using voltage levels that range from 4kV to 66kV.

Breakers:

Description: Breakers are strategically located throughout the bulk electric transmission system at voltages ranging from 4-kV to 66-kV and allow utility operators to control the flow of power by opening and closing breakers either locally or remotely from the System Control Center. There are several different types of breaker technology used including SF6 (or a mix of gases), air blast, vacuum and oil filled units.		
Degradation: • Insulation degradation • Mechanical Wear due to normal and fault operations • Obsolescence & depletion of spares • Poor connections	**Expected Life:** 60-65 years	**Turnover based on Current Replacement Rate:** 180 years[19]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	290	16.19%
10 to 20	170	9.49%
20 to 30	206	11.50%
30 to 40	94	5.25%
40 to 50	415	23.17%
50 to 60	473	26.41%
60 to 70	93	5.19%
70 to 80	9	0.50%
80 to 90	22	1.23%
> 90	0	0.00%
Not Available	19	1.06%
Grand Total	1791	100.00%
Replacement Value	$359M	

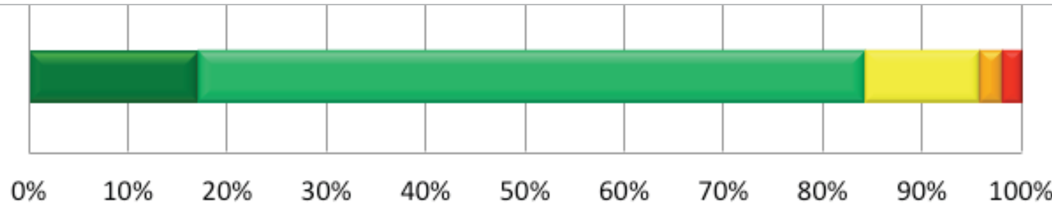


	Asset Quantity	Population Breakdown
Very Good	441	24.6%
Good	532	29.7%
Fair	774	43.2%
Poor	44	2.5%
Very Poor	0	0.0%

Station Transformers:

Description:		
Station Class transformers are necessary to convert electrical energy from one voltage to another for the purposes of delivering bulk electric power over long distances. Tap changers are a component that can be added to a transformer to allow small incremental changes to the voltage ratio based on changing positions of the tap changer. This functionality is used for voltage regulation purposes.		
Degradation: • Insulation degradation or contamination due to heating (loading) or moisture • Corrosion • Mechanical deterioration of tap changer due to operations • Mechanical damage due to through faults or physical impact	**Expected Life:** 40-70 years[20]	**Turnover based on Current Replacement Rate:** 370 years[21]

Demographics		
AGE (Yrs)	Qty	%
0 to 10	21	2.84%
10 to 20	49	6.63%
20 to 30	74	10.01%
30 to 40	66	8.93%
40 to 50	294	39.78%
50 to 60	151	20.43%
60 to 70	55	7.44%
70 to 80	13	1.76%
80 to 90	13	1.76%
> 90	3	0.41%
Grand Total	739	100.00%
Replacement Value	$700M	

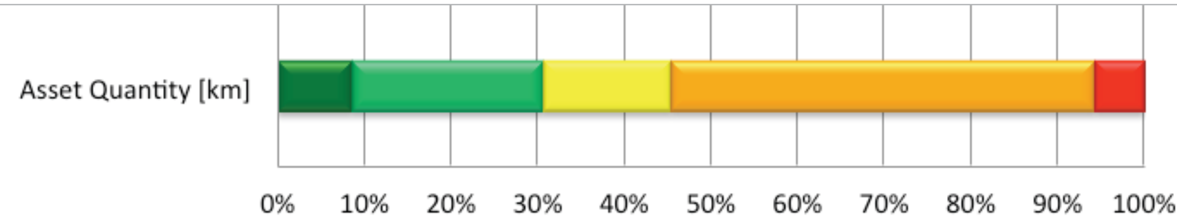


	Asset Quantity	Population Breakdown
Very Good	126	17.05%
Good	497	67.25%
Fair	85	11.50%
Poor	16	2.17%
Very Poor	15	2.03%

Underground Cable:

Description: Underground cables are heavily insulated conductors, installed below grade, that are used to distribute electricity from a source (Distribution Stations) to padmount transformers. The insulating medium is a requirement not found on overhead conductors and allows the cables to be installed directly in the ground. The majority of these conductors are aluminum; however, some are copper. The insulation surrounding the cable can vary, from oil impregnated paper (PILC) to rubber (RINJ/RIPVCJ) to cross link polyethylene (XLPE/TRXLPE).		
Degradation: • Mechanical Damage (contact by construction crews, loss of oil due to leaks) • Electrical (heat from overloading decays cable insulation) • Environmental (moisture from surrounding soil permeates the insulation)	**Expected Life:** 30-70 years[22]	**Turnover based on Current Replacement Rate:** 328 years

Demographics		
Age (Yrs)	Total (km)	%
0 to 10	949.9	15.7%
10 to 20	867.4	14.3%
20 to 30	1,398.7	23.0%
30 to 40	2,026.3	33.4%
40 to 50	570.8	9.4%
50 to 60	66.2	1.1%
60 to 70	67.7	1.1%
70 to 80	67.7	1.1%
> 80	54.1	0.9%
Grand Total	6,069.0	100.0%
Replacement Value	$1,500M	

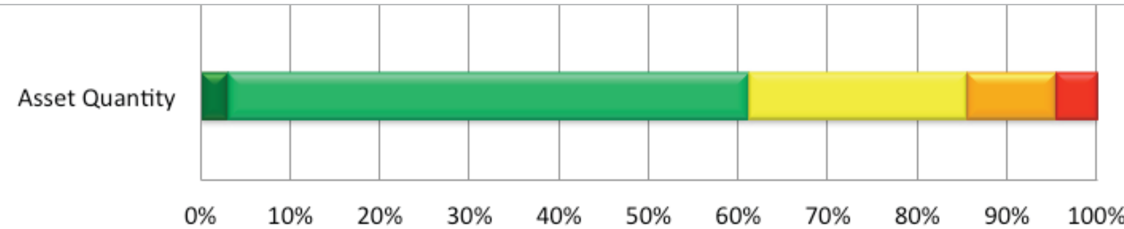


	Asset Quantity [km]	Population Breakdown
Very Good	518.09	8.5%
Good	1,340.07	22.1%
Fair	899.54	14.8%
Poor	2,970.17	48.9%
Very Poor	340.87	5.6%

Manholes:

Description: Manholes are concrete vaults that are built below grade and used to install and splice underground cables in heavily congested underground urban areas. The majority of the manholes are located in the downtown core of Winnipeg, with the remainder found in suburban areas of Winnipeg and Brandon.		
Degradation: • Mechanical (ground movement, vibration due to vehicular traffic) • Environmental (soil condition, tree roots)	**Expected Life:** 80 years	**Turnover based on Current Replacement Rate:** 500 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	67	2.8%
10 to 20	472	19.6%
20 to 30	517	21.5%
30 to 40	458	19.0%
40 to 50	218	9.0%
50 to 60	218	9.0%
60 to 70	156	6.4%
70 to 80	93	3.9%
80 to 90	93	3.9%
90 to 100	60	2.5%
>100	57	2.4%
Grand Total	2,409	100.0%
Replacement Value	$301M	

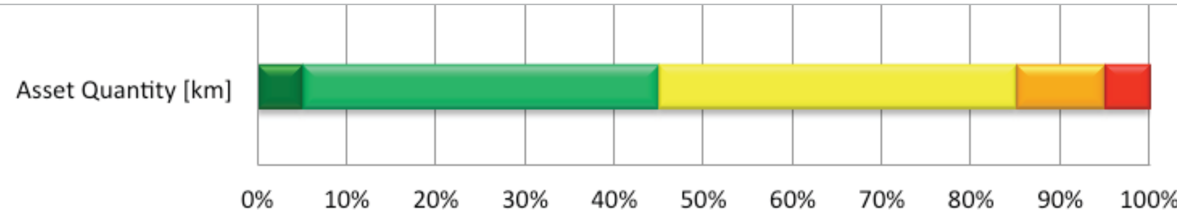


	Asset Quantity	Population Breakdown
Very Good	74	3.1%
Good	1,397	58.0%
Fair	587	24.4%
Poor	243	10.1%
Very Poor	108	4.5%

Duct Lines:

Description: Ductlines are made up of bundled PVC pipes that are encased in an envelope of concrete. They are installed below grade between manholes and are used to provide an underground path for high voltage cables in heavily congested areas. They are most commonly found in the downtown core of Winnipeg, but are also used in suburban areas of Winnipeg and Brandon.		
Degradation: • Mechanical (ground movement, vibration due to vehicular traffic) • Environmental (soil condition, tree roots) • Age of construction material	**Expected Life:** 100 years	**Turnover based on Current Replacement Rate:** 378 years[23]

Demographics		
Age (Yrs)	Total (km)	%
0 to 10	12.0	4.5%
10 to 20	36.5	13.8%
20 to 30	39.3	14.8%
30 to 40	39.3	14.8%
40 to 50	39.3	14.8%
50 to 60	39.3	14.8%
60 to 70	24.7	9.3%
70 to 80	10.2	3.8%
80 to 90	10.2	3.8%
90 to 100	7.3	2.8%
>100	7.0	2.6%
Grand Total	265.0	100.0%
Replacement Value	$795M	

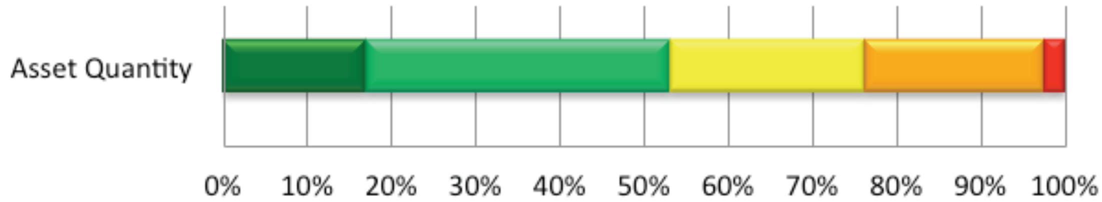


	Asset Quantity [km]	Population Breakdown
Very Good	13.2	5.0%
Good	106.0	40.0%
Fair	106.0	40.0%
Poor	26.5	10.0%
Very Poor	13.3	5.0%

Padmount Transformers:

Description: These transformers are used to step high voltage power (24kV and below) down to a voltage that is usable by customers (600V and below). The service point between Manitoba Hydro and the customer is generally located immediately downstream of the secondary side of these units. These transformers, both single phase and three phase, are located at ground level on top of fiberglass or concrete pads.		
Degradation: • Ambient Temperature • Wind • Loading • Corrosion due to exposure to environment (contact with moist soil, road salt, limited air flow)	**Expected Life:** 50 years	**Turnover based on Current Replacement Rate:** 70 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	7,296	38.6%
10 to 20	3,557	18.8%
20 to 30	3,453	18.3%
30 to 40	3,440	18.2%
40 to 50	1,140	6.0%
Total	20,435	100.0%
Replacement Value	$273M	

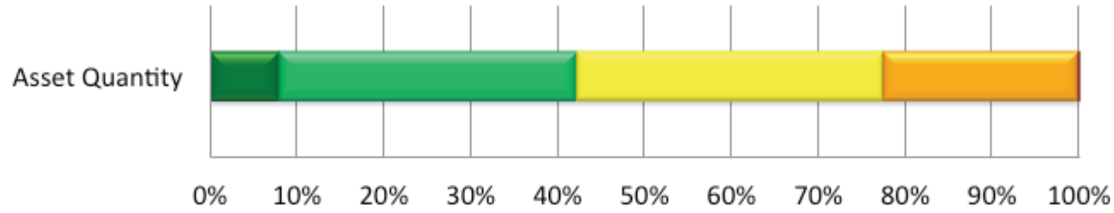


	Asset Quantity	Population Breakdown
Very Good	3,190	16.9%
Good	6,839	36.2%
Fair	4,363	23.1%
Poor	4,056	21.5%
Very Poor	437	2.3%

Wood Poles:

Description: Wood poles are used to provide ground clearance and to support conductors and energized equipment installations on the pole. In addition to holding up overhead lines, the pole can also support equipment installations, such as overhead distribution transformers and transition structures between overhead conductors and underground cables.		
Degradation: • Environmental (moisture causing shell rot, wood destroying fungi, insect infestation) • Mechanical Damage (contact with snow plows and vehicular traffic)	**Expected Life:** 75 years	**Turnover based on Current Replacement Rate:** 200 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	143,873	13.3%
10 to 20	157,792	14.6%
20 to 30	170,517	15.7%
30 to 40	173,802	16.1%
40 to 50	174,556	16.1%
50 to 60	144,486	13.3%
60 to 70	113,771	10.5%
70 to 80	3,313	0.3%
> 80	762	0.1%
Grand Total	1,082,873	100.0%
Replacement Value	$3,500M	



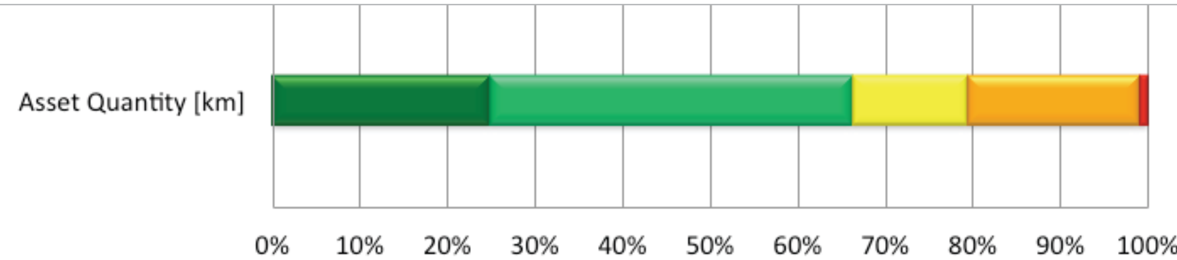
	Asset Quantity	Population Breakdown
Very Good	85,192	7.9%
Good	371,713	34.3%
Fair	380,387	35.1%
Poor	243,768	22.5%
Very Poor	1,813	0.2%

Overhead Primary Conductor:

Description:
Like the Transmission overhead conductor, these are the main high voltage, current carrying wire that distributes power from source (distribution stations) to load (the customer). These wires are generally made of bare aluminum alloy; however, some copper lines are still in operation. Some of these lines are covered by a polyurethane sheet; however, most are not.

Degradation:	**Expected Life:**	**Turnover based on Current Replacement Rate:**
• Mechanical (ice build-up, tree strikes) • Electrical (capacity overloading due to general load growth, high fault levels)	100 years	200 years[24]

Demographics		
Age (Yrs)	km	%
0 to 10	38,073.5	33.2%
10 to 20	23,373.8	20.4%
20 to 30	14,349.5	12.5%
30 to 40	8,809.4	7.7%
40 to 50	5,408.2	4.7%
50 to 60	16,142.7	14.1%
60 to 70	7,302.0	6.4%
70 to 80	543.6	0.5%
80 to 90	333.7	0.3%
90 to 100	204.9	0.2%
>100	125.8	0.1%
Grand Total	114,882.0	100.0%
Replacement Value	$700M	



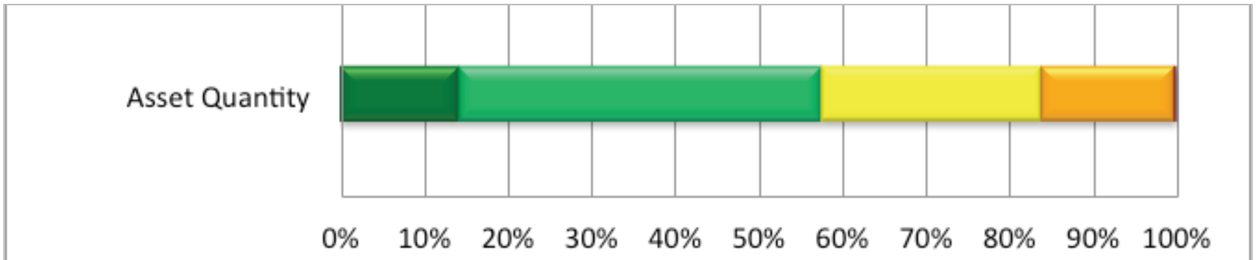
	Asset Quantity [km]	Population Breakdown
Very Good	28,530.8	24.9%
Good	47,266.0	41.2%
Fair	15,017.0	13.1%
Poor	22,500.9	19.6%
Very Poor	1,352.3	1.2%

Overhead Transformers:

Description:
These transformers are used to step high voltage power (24kV and below) down to a voltage that is usable by customers (600V and below). The service point between Manitoba Hydro and the customer is generally located immediately downstream of the secondary side of these units. These transformers, both single phase and three phase, are attached to wood poles just below the primary overhead lines.

Degradation:	**Expected Life:**	**Turnover based on Current Replacement Rate:**
• Ambient Temperature • Wind • Loading • Exposure to environment (wildlife, lightning strike, tree strike)	75 years	70 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	40,139	27.7%
10 to 20	29,935	20.7%
20 to 30	21,172	14.6%
30 to 40	17,192	11.9%
40 to 50	15,731	10.9%
50 to 60	12,153	8.4%
60 to 70	7,923	5.5%
70 to 80	255	0.2%
80 to 90	207	0.1%
> 90	53	0.0%
Grand Total	145,798	100.0%
Replacement Value	$494M	

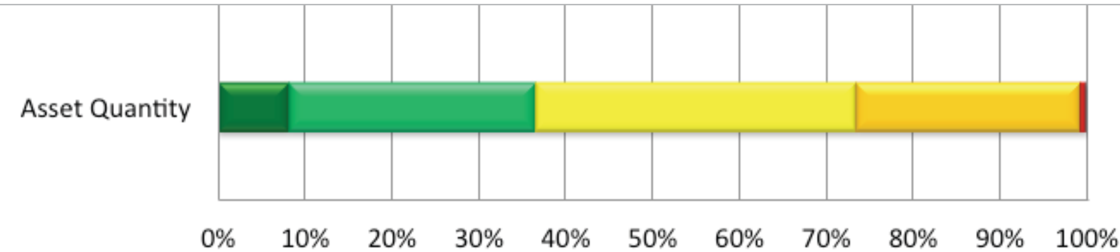


	Asset Quantity	Population Breakdown
Very Good	20,381	14.1%
Good	62,797	43.4%
Fair	38,148	26.4%
Poor	22,919	15.8%
Very Poor	515	0.4%

Street Lights:

Description:		
Streetlight standards typically consist of a tubular steel or aluminum. This supports the lights and is used to provide roadway lighting in urban and high traffic locations. The majority of Manitoba Hydro street lights are concentrated within the City of Winnipeg and to a lesser extent in other large urban centers in the province. Street lights are generally installed on a pre-formed concrete base; however, can also be installed directly into the ground.		
Degradation: • Corrosion due to exposure to environment (contact with moist soil, road salt) • Mechanical Damage (contact with snow plows and vehicular traffic) • Installation methods • Material	**Expected Life:** 50-70 years[25]	**Turnover based on Current Replacement Rate:** 100 years

Demographics		
Age (Yrs)	Qty	%
0 to 10	11,107	19.1%
10 to 20	7,267	12.5%
20 to 30	9,789	16.8%
30 to 40	10,815	18.6%
40 to 50	9,884	17.0%
50 to 60	7,558	13.0%
60 to 70	1,474	2.5%
70 to 80	27	0.0%
80 to 90	58	0.1%
90 to 100	50	0.1%
> 100	196	0.3%
Grand Total	58,225	100.0%
Replacement Value	$282M	



	Asset Quantity	Population Breakdown
Very Good	4,685	8.0%
Good	16,498	28.3%
Fair	21,696	37.3%
Poor	14,991	25.7%
Very Poor	355	0.6%

5. Current vs. 20 year Forecast of Asset Condition

The following condition assessment demographic charts estimates the impact on the condition of the assets if Manitoba Hydro implements the currently approved Capital Expenditure Forecast 2013 (CEF 13). CEF 13 includes approved spending for projects to refurbish and replace assets as well as asset sustainment programs. In some cases the CEF 13 does not capture the spending requirements surrounding program renewals and projects for assets that had not begun to show signs of significant deterioration at the time it was put together and there is no remaining funds to address these replacements.

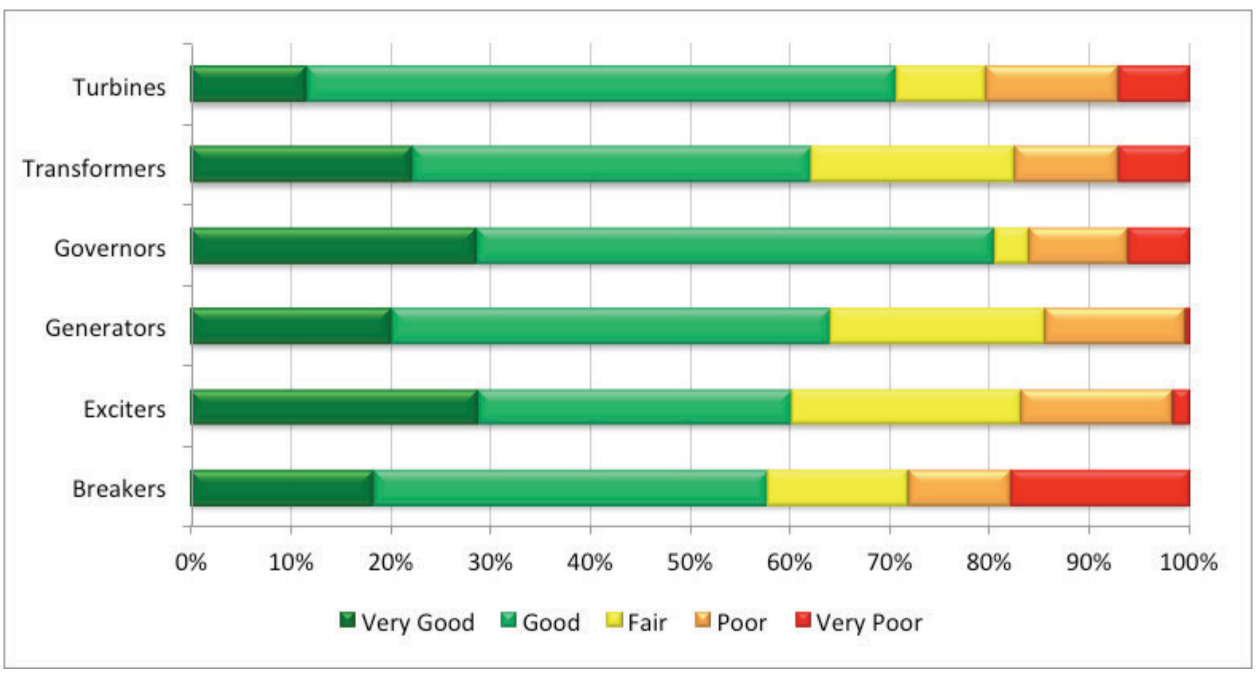
The charts are arranged so the reader can compare the current condition of all assets in each business unit to the forecasted condition 20 years from now.

The 20-year asset outlook for Generation Operations, Transmission and Distribution indicates significantly poorer asset health compared to current day conditions. Generation Operations, HVDC and transmission battery bank condition is not displayed in the forecast as they are replaced to maintain reliability at the end of their expected life.

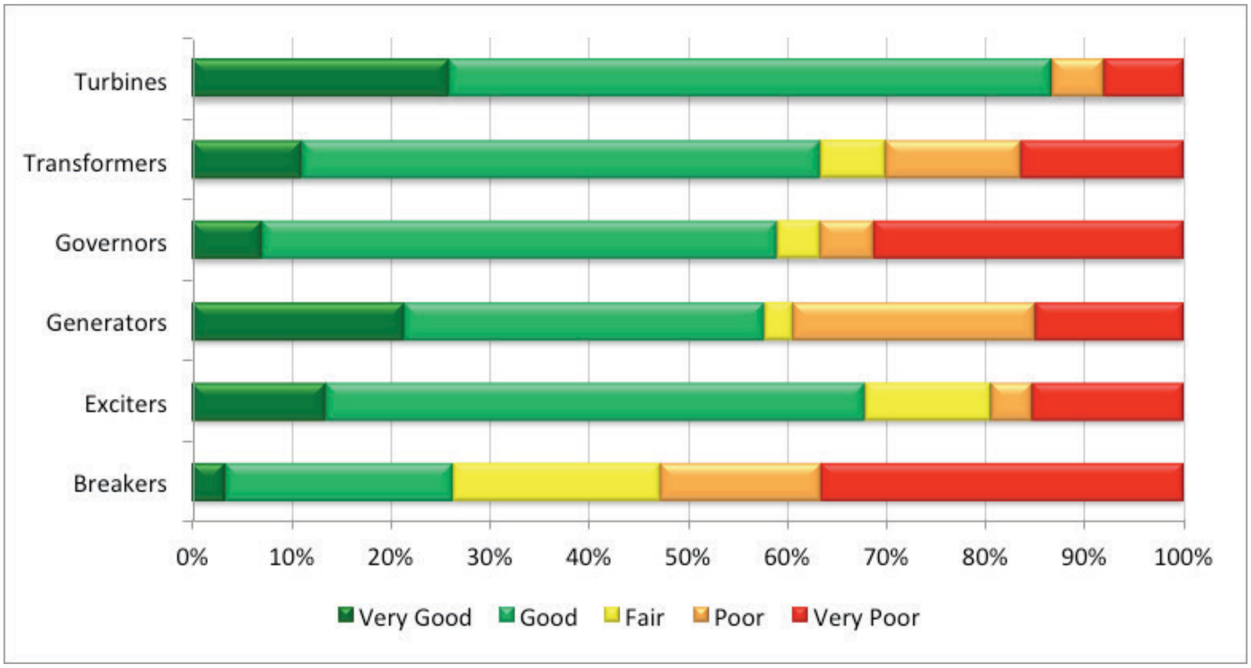
An alternative funding and resource plan will be required over the next 20 years to maintain or improve the overall condition of the Generation Operations, Transmission and Distribution Assets. This is based on the current asset condition and the effective remaining life that may dictate asset replacement.

GENERATION OPERATIONS

Current Asset Condition Assessment



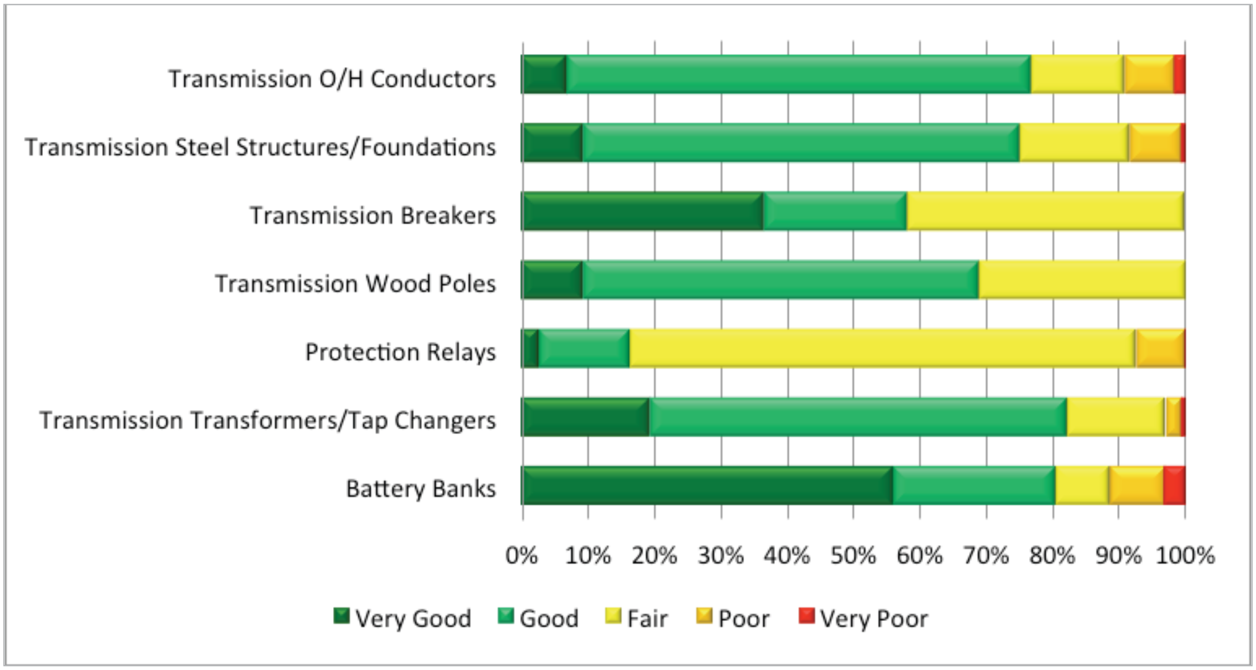
20 year Asset Condition Assessment Forecast



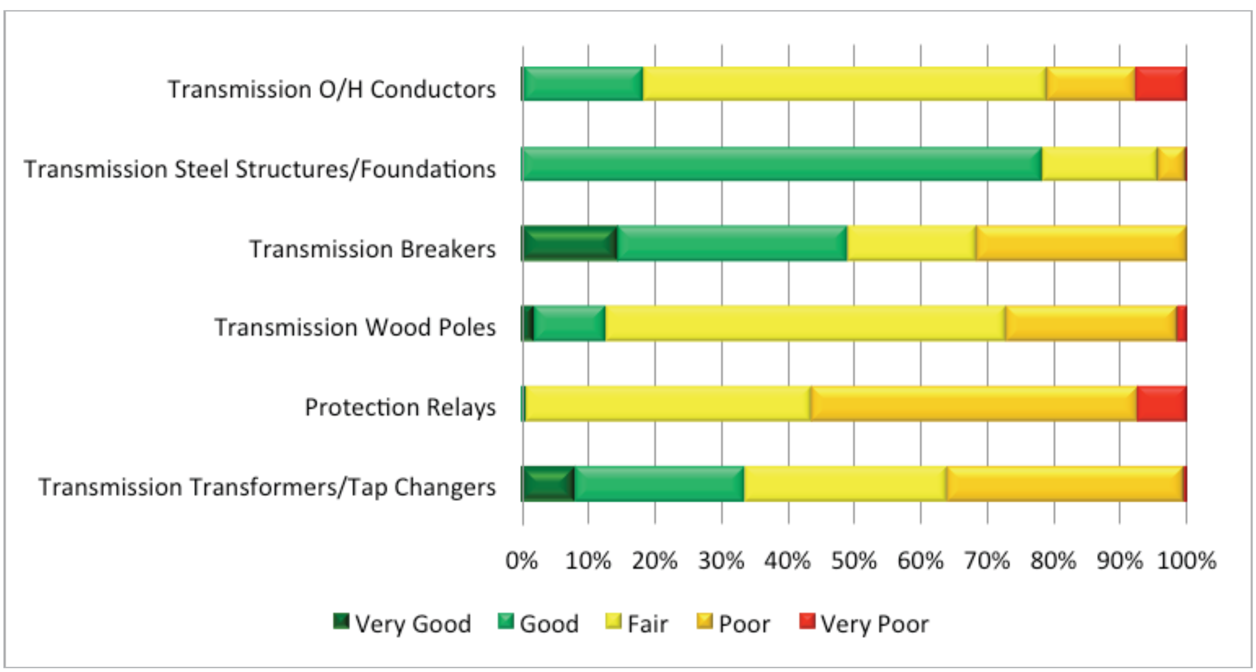
In the case of generators, the increased count of "poor" and "very poor" is due to having limited funds presently in place for their replacement. A generator replacement can cost up to $30,000,000 and in the event of limited funds it is often favorable to defer this work and address more less costly assets. The deferral of a generator replacement increases the risks of in-service failures. Many of the digital governors have an end of life which occurs within the 20-year forecast period. If there is not a project in place to address these assets, the funding may not be available and the assets will be run to the poorest condition. The transformer and breaker conditions will continue to drop as the funded work on these assets is currently not sufficient to address their excessive age.

TRANSMISSION

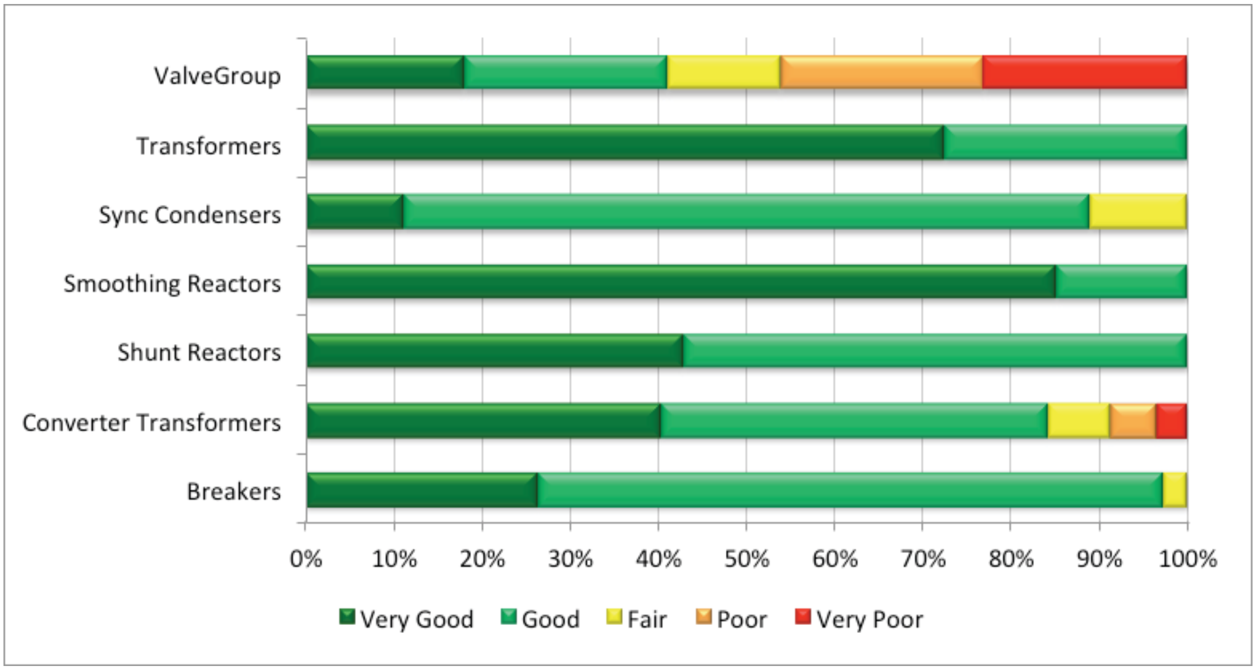
Transmission Summary of Assets



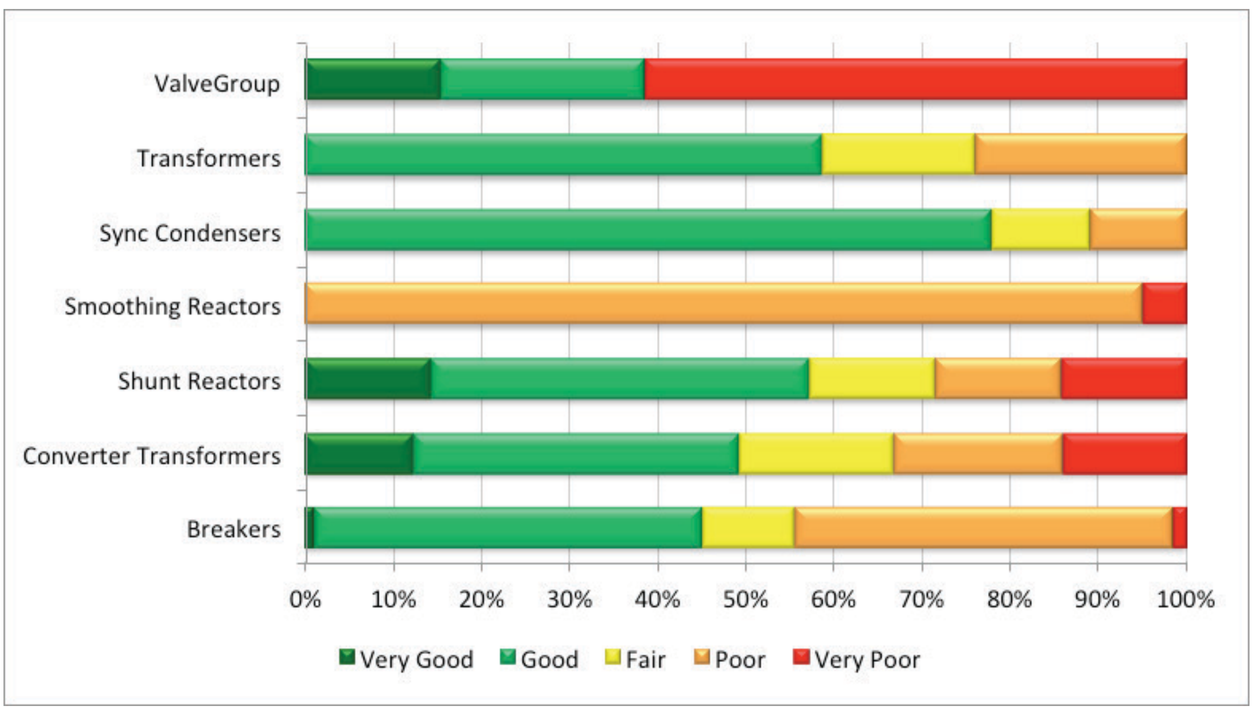
Transmission 20 Year Asset Forecast



HVDC Summary of Assets



HVDC 20 Year Asset Forecast



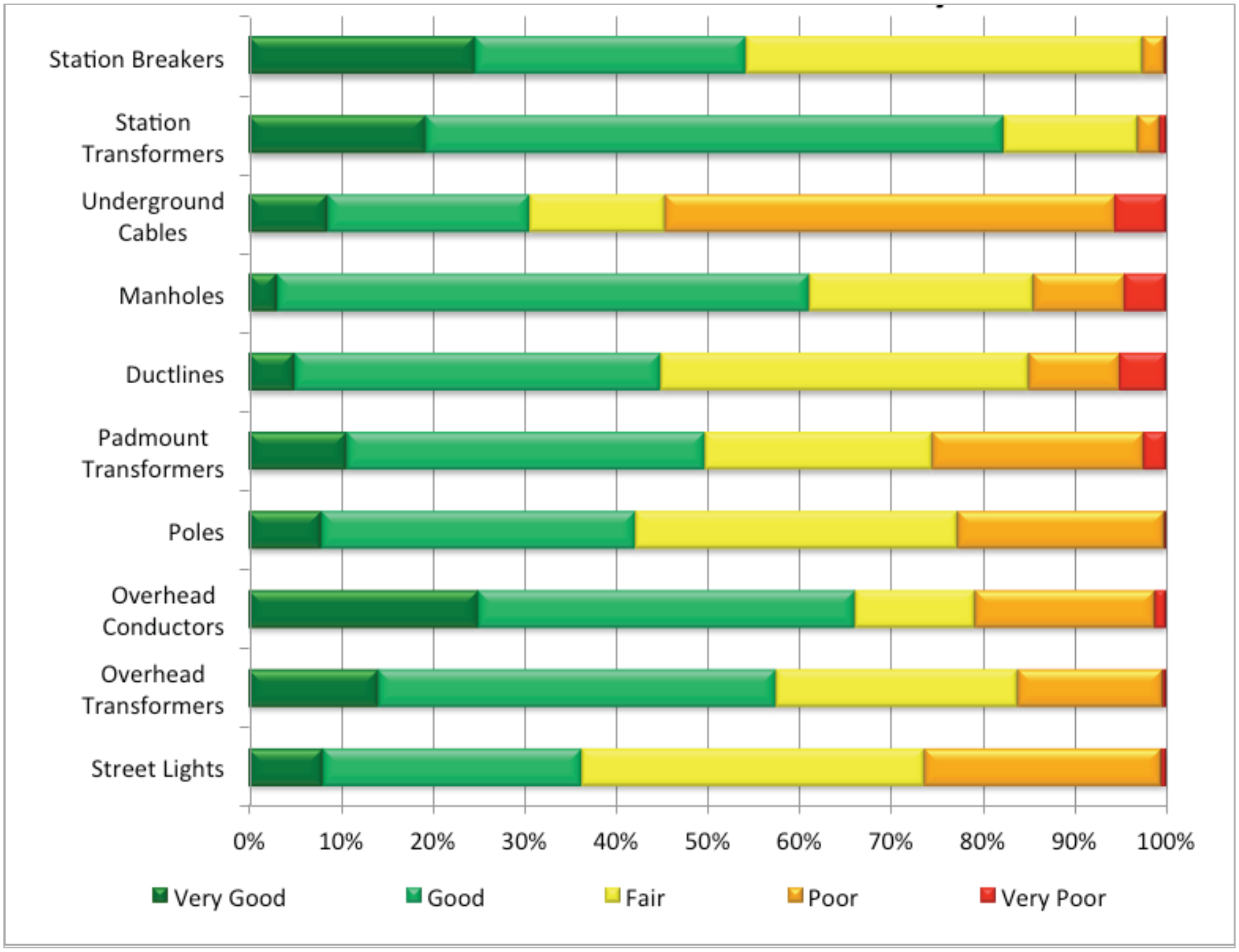
The Transmission 20 year forecast includes approved capital sustainment programs for breakers, transformers and transmission line wood pole structures. It should also be noted that capital projects/programs currently being executed will address Transmission O/H Conductor assets that are currently in “Very Poor” condition. There are also currently foundations associated with steel structures that are scheduled for repair due to condition.

In the case of breakers and protection relays, the increase in assets of “poor” and “very poor” condition is due in part to the effects of age and our declining ability to support the existing assets with obsolescence issues and/or a dwindling supply of spare parts, which limits the ability to extend “useful life”. For protection relays, it should be noted that the outlook does not include the impact of all future replacements associated with capacity enhancement projects. This is expected to impact less than 5% of the protection relays considered in this report. Wood poles, steel structures, conductors and transformers deteriorate into the “poor” category due mainly to the effects of aging and continued utilization. The transmission line asset forecasts do not include the impact of the Transmission Line Upgrades for NERC Alert project. These impacts will be incorporated into future forecasts as additional project details become available.

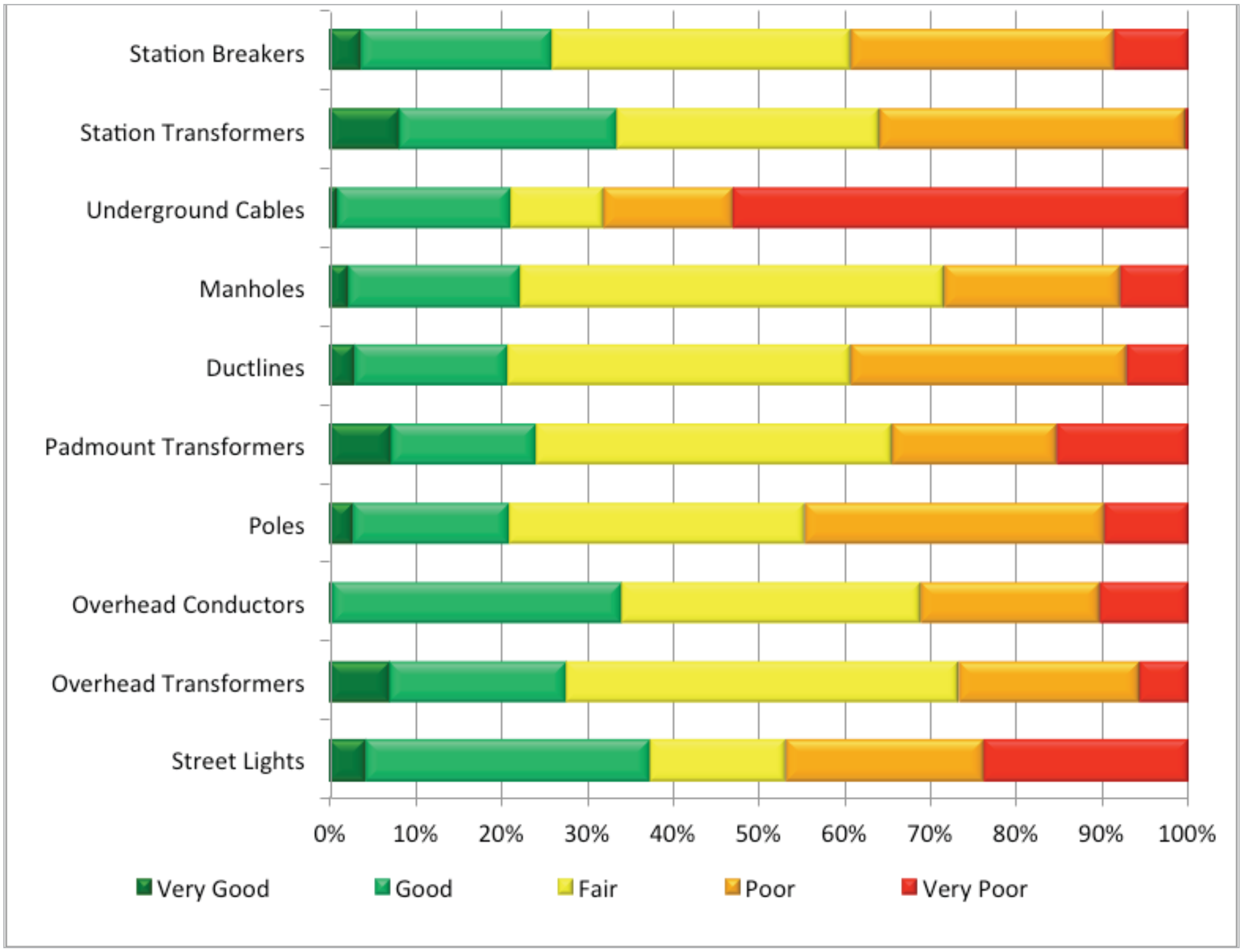
The HVDC 20 year forecast includes approved capital sustainment programs for breakers, transformers, synchronous condensers and valve groups. In the case of smoothing reactors, and valve groups, the increase in assets of “poor” and “very poor” is due to these assets reaching expected end of life prior to the 20 years occurring. Air core smoothing reactors deteriorate into the “poor” category in the last few years of the 20 year outlook due mainly to expected life. Since this is a new type of smoothing reactor, this forecast is based on industry guidelines for replacement. As Manitoba Hydro gains experience with this type of smoothing reactor, the condition forecast will be updated accordingly. It should also be noted that the Pole 2 Valve Group does not move into the Very Poor condition category until the last two years of the 20-year outlook period. HVDC Engineering is currently performing assessments of options to extend the life of the Bipole 1 Valve Group. The outcome of this work may modify the Valve Group condition forecast.

DISTRIBUTION

Current Distribution Summary of Assets



Distribution 20 Year Asset Forecast



As poles installed during the rural electrification program approach end of life, a dramatic increase in pole replacements is anticipated. Current resources will not be able to meet this demand and as a result, a significant increase in the number of assets transitioning from “poor” to “very poor” condition is expected. This is also anticipated for underground cables, as the majority of XLPE lines installed in the early 1980’s are also approaching end of life. It is forecasted that current cable replacement rates will not be able to meet the demand for this asset replacement. A similar trend will see a dramatic increase in street lights transitioning from “fair” to “poor” as a large segment of the direct installed assets will reach end of life within the next 20 years. The condition of these assets will continue to drop as the funded programs are currently not sufficient to address their excessive age.

Appendix A: Definitions and Acronyms

Definitions:

i. Asset Age = This criterion identifies how many years the asset has been in service or the date of manufacture (depending on data availability). For some asset classes, asset age remains a key criterion for evaluating asset health because it is more cost-effective and efficient to have a maintenance program that allows assets to run to failure with no condition assessments. For example, overhead transformers on the distribution system are run to failure.

ii. Expected life = The typical life span of an asset, provided it is not replaced sooner for other reasons such as government regulations, economic justification, system development, performance, safety issues, obsolescence/lack of spare parts, and/or unusual condition degradation. Under favorable operating environments, the asset may exceed its typical life span.

iii. In service = Equipment that is installed and energized, and seeing active commercial duty.

Acronyms:

ACSR= Aluminum Conductor	ACA= Asset Condition Assessment
Steel Reinforced	ASC= Armor Sheathed Cable
AHI= Asset Health Index	AH= Asset Health
AMPS= Applied Maintenance Planning System	ASTM= American Society for Testing and Materials
CB= Circuit Breaker	CEF= Capital Expenditure Forecast
CEATI= Center for Energy Advancement through Technological Innovation	CH4= Methane
C2H6= Ethane	C2H4= Ethylene
C2H2= Acetylene	CO= Carbon Monoxide
CO2= Carbon Dioxide	CO2/CO= Carbon Dioxide/Carbon Monoxide
CPF= Sub-Condition Parameter Score	CPS= Condition Parameter Score
CSC= Customer Service Center	DC= Direct Current
DGA= Dissolved Gas Analysis	DMPS= Distribution Maintenance Planning System

DR= De-Rating Multiplier	eGIS= electronic Geographic Information System
EPRI= Electrical Power Research Institute	H2= Hydrogen
HI= Health Index	HMI= Human Machine Interface
HVDC= High Voltage Direct Current	IFT= Interfacial Tension
IR= Infrared	LMA= Loss of Metallic Area
LTC= Load Tap Changer	MCC= Motor Control Center
PILC= Paper Insulated Lead Covered Cables	RINJ= Rubber Insulated Neoprene Jacket
RIPVCJ= Rubber Insulated Poly Vinyl Chloride Jacket Cables	RTS= Rated Tensile Strength
SF6= sulfur hexafluoride	SFC= Stat Frequency Converter
SFRA= Swept Frequency Response Analysis	TRXLPE= Tree Retardant Cross Linked Poly Ethylene
WCP= Weight of Condition Parameter	WCPF= Weight of Sub-Condition Parameter
XLPE= Cross Linked Poly Ethylene Cables	

Appendix B: Generation Operations Detailed Methodology

GENERATION OPERATIONS

Asset Condition Assessment Methodology

Manitoba Hydro's methodology determines Asset Health (AH) by performing standardized equipment condition assessments as part of the maintenance program. Technical experts take the condition assessment and factor in the field feedback and their judgment in conjunction with the engineers, the asset's age, life curve, and performance to calculate the AHI. This provides a more accurate and reliable index of asset health that aligns better with asset management.

The general breakdown of each assets health index methodology includes:

- Providing general descriptions of each asset class
- Showing the demographics of each type of asset
- Describing condition assessment techniques for each asset class
- Determining end-of-life criteria based on condition assessments of each asset class
- Formulating the Asset Health Index using data from asset health, age, performance and life curve.
- Calculating a numerical condition score for each equipment asset class to indicate the reliable service life remaining.
- Ensuring repeatability, by documenting the methodology and data sources used.

The results are used to help decide acceptable risk and clarify the consequences of an asset's criticality issues, determine acceptable reliability goals, ensure compliance requirements are met, and meet performance expectations.

Transformers:

The following tests/inspections were considered in calculating a condition index score:

- Furan levels in oil
- Dissolved Gas Analysis
- Capacitance Bridge and Dissipation Factor
- Operations & Mtce History (see Hydro AMP guide for more details on this)
- Age
- DC Winding Resistance Test
- Turns Ratio Test

In select cases, the following test results were considered (where available):

- Core-to-Ground Resistance (Megger)
- Swept Frequency Response Analysis (SFRA)
- Internal Inspections
- Degree of Polymerization (based on internal inspections and furan levels in oil)

Generators:

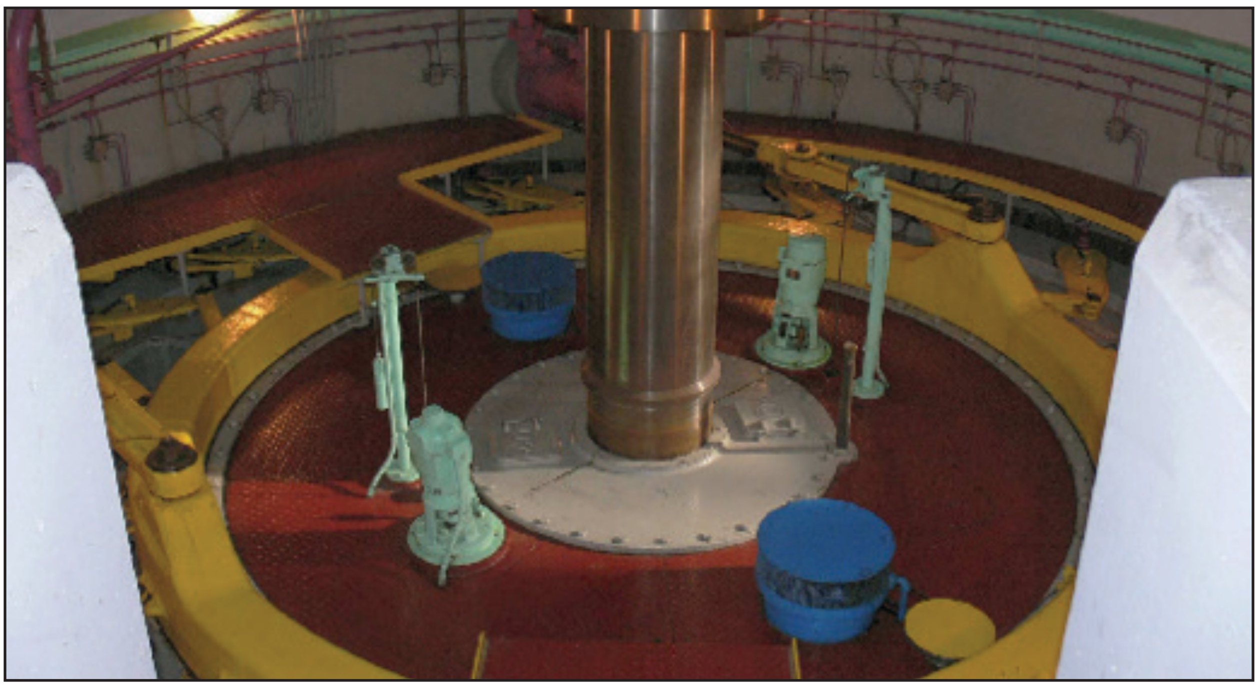
The generators were reviewed using routine historical testing data (high direct voltage ramp). In addition factors such as age, neighboring unit condition, and overhaul history were used to create the condition scores and replacement dates.

Turbines:

For determining the condition score of the Turbines, a combination of the following methods was used:

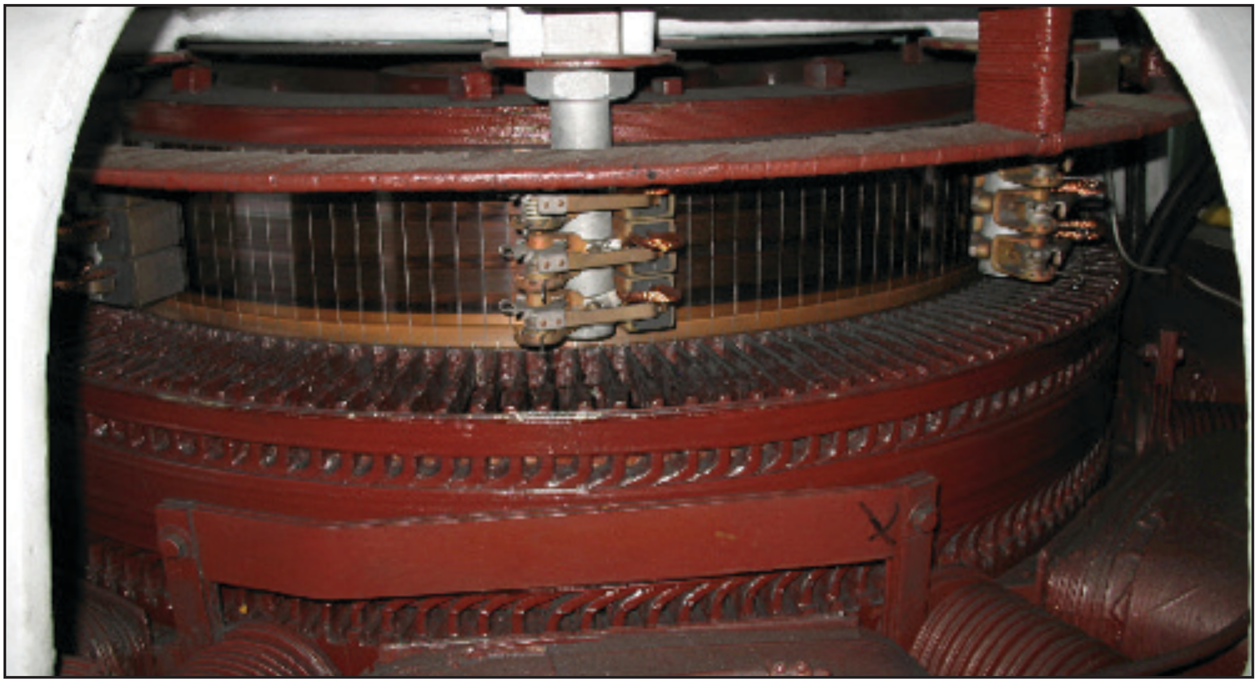
- Interviews with site maintenance staff to determine any known issues on each turbine based on existing maintenance record and staff experience.
- Review of available past maintenance records, engineering drawings, and relevant reports.
- Scheduled outage-based Non-Destructive Examination of major turbine components, including the runner, shaft, visible embedments, headcovers, and control system components.

The above information gathering and inspection process is currently ongoing, and largely dependent on scheduled unit maintenance outages. The initial pre-inspection scoring is based on the interview and information research phases, which prioritizes the inspection sequence.



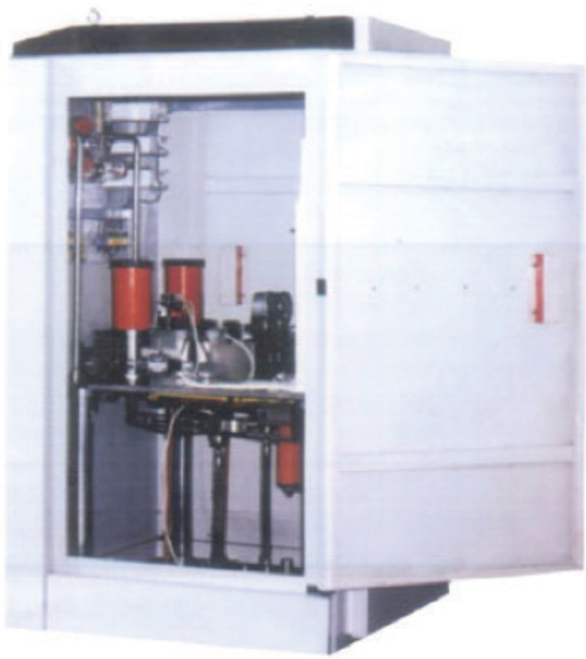
Exciters:

The excitation systems were reviewed on a family of exciters basis versus an individual basis. The approach was appropriate due to the short equipment life of the products. Individual performance deviations were treated as resolvable issues through routine maintenance.



Governors:

Condition scores were generated by applying an age and performance based score to each type of governor. Most governors in our system do not have performance issues so the majority of the scores are based on age. This score was combined with empirical knowledge to generate an adjusted value which was agreed to under consensus by hydro maintenance engineers to best represent actual condition and expected life.



Breakers:

The equipment condition evaluation involved the review and assessment of the following criteria:

- Equipment performance information from the following sources:
    - Electronic defective work order information and notes contained within Applied Maintenance Planning System- AMPS
    - Reliability information from Apparatus Maintenance Reliability Reports, Center for Energy Advancement through Technological Innovation (CEATI), Electrical Power Research Institute (EPRI) and others
    - Paper maintenance documentation from site

- Maintenance records from the following sources:
    - Electronic maintenance work order information and notes contained within AMPS
    - Paper maintenance documentation from site
    - Electronic circuit breaker analysis results if available
    - Insulation test results in electronic and paper form

- Evaluation of Equipment Obsolescence
    - Equipment age
    - Spare parts availability from the following sources:
        - AMPS stores inventory
        - Apparatus Maintenance Stores inventory
        - Salvaged parts inventory
        - Original equipment manufacturer
    - Technical Support availability from the following sources:
        - Internal staff
        - Original equipment manufacturer
        - Other equipment support companies


52G Generator Breaker & 29G Disconnect (Typical)

Battery Banks:

- Visual inspections
- Past test data (if available) (resistance(now)/conductance(before), specific gravities, and voltages)
- Previous performance of batteries if they have been put to use (i.e. AC power loss and batteries were called upon to carry the DC load)
- Past maintenance records

Appendix C: Transmission Detailed Methodology

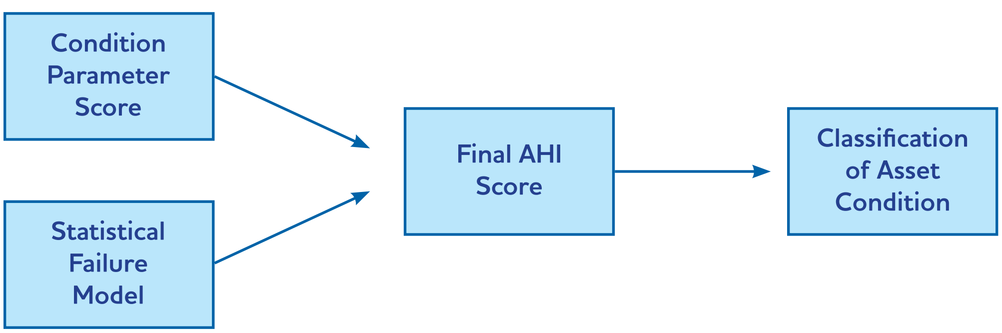
TRANSMISSION

Asset Condition Assessment (ACA) Methodology

Background:

The Transmission Business Unit (BU) began its asset condition assessments in 2012 by hiring a third party consultant with expertise in the development of condition assessment methodologies for utility grade high voltage (HV) equipment. This third party consultant worked with Transmission's subject matter experts to provide asset condition assessment methodologies and statistical failure models for transmission system station transformers, tap changers, breakers and transmission wood poles structures. The remaining Transmission asset condition assessment methodologies presented in this report, while similar in approach, were developed by the Transmission Asset Strategies group in consultation with subject matter experts across the Business Unit. This section describes these methodologies.

Where an asset has a statistical failure model available, the model has been incorporated into the AHI scoring methodology. The purpose of this is to increase the extent to which the AHI reflects the likelihood of failure. Statistical failure models were available for breakers, transformers and transmission line wood pole structures. These models were provided by the above mentioned consultant and were based on the consultant's industry failure curves, on subject matter expert input and limited failure data provided by Manitoba Hydro and on the consultant's proprietary methodology to link condition parameter scores to probability of failure.



Transmission will continue to evolve its existing condition assessment methodologies as it gains experience with these models and to develop and implement new condition assessment models for asset classes such as instrument transformers and equipment bushings, to the extent that there's a positive business case to do so.

The boundaries between the different classifications of the AHI Score (i.e. Very Good, Good, Fair, Poor and Very Poor) were determined using the classification definitions provided in Section 4 of the report.

Transmission System Substation Transformers

Health Index Formulation

This report presents a transformer/tap changer AHI score distribution that, where applicable, reflects the combined AHI scores of the transformer (main tank) and tap changer. The combined AHI score is intended to reflect the likelihood that either the transformer or the tap changer will fail and need to be replaced or refurbished. It should be noted that the remedial action for a main tank failure may be very different from the remedial action required for a tap changer failure.

The health index formulation for the transformer main tank uses condition parameters that significantly contribute to the long-term degradation of the transformer. For substation transformers the condition parameters and sub-condition parameters were selected as follows:

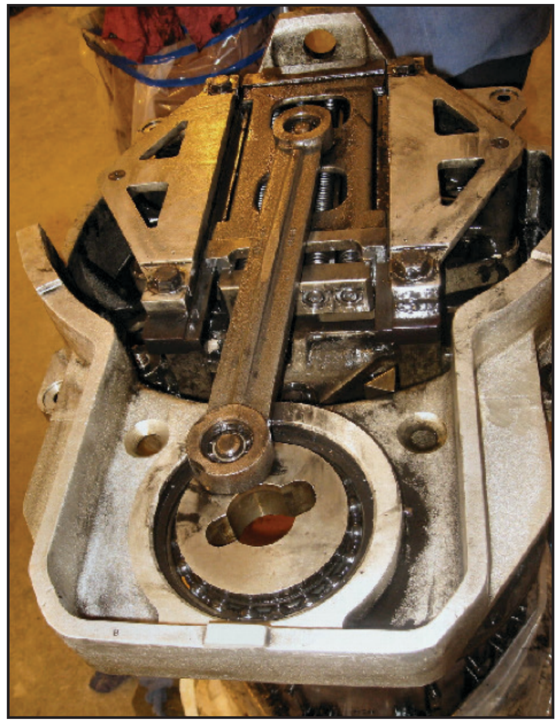
- Insulation
    - Oil Quality
    - Oil DGA
    - Power dissipation*
    - Insulation Issues
- Cooling
    - Cooling system
- Sealing and connection
    - Insulation containment
    - Tank condition
    - Grounding
    - Oil conservator
    - Connections
- Service record
    - Loading*
    - Age

*When available in electronic format.

Where available, source data used for calculating Asset Health Index scores was taken from various Transmission electronic database systems as well as actual test results. Additional factors such as known design flaws or performance issues were also accounted for in the AHI.

Transmission System Load Tap Changers

Health Index Formulation



For transformer tap changers the condition parameters and sub-condition parameters have been selected as follows:

- Operating mechanism
  - Switch/contact
  - Tap selector head
  - Diverter
  - Control – Electrical
  - Control – Mechanical
  - Cabinet
  - Pressure relief
- Arc extinction
  - Diverter vacuum
  - Contacts
- Sealing and connection
  - Gasket or sealant
  - Oil level
  - Breather
- Insulation
  - Oil DGA
  - Oil quality
  - Insulation
- Service record
  - Operations
  - Failure to operate
  - Age

For transformer tap changers, the operating mechanism, sealing & connection, arc extinction and service record sub-condition parameter inputs were supplied by data and/or corrective maintenance records obtained from an electronic maintenance database(s) whereas much of the insulation sub-condition parameter inputs were supplied by actual test data. Additional factors such as obsolescence, known design flaws or performance issues were also accounted for in the AHI.

HVDC System Transformers:

The following tests/inspections were considered in calculating a condition index score:

- Furan levels in oil
- Dissolved Gas Analysis
- Capacitance Bridge and Dissipation Factor
- Operations & Mtce History
- Age
- On Load Tap Changer condition
- DC Winding Resistance Test
- Turns Ratio Test
- Core-to-Ground Resistance (Megger)
- Swept Frequency Response Analysis (SFRA)
- Internal Inspections
- Degree of Polymerization (based on internal inspections and furan levels in oil)
  The transformers have a useful life expectancy of 40-70 years.

Transmission System Circuit Breakers

Health Index Formulation

For circuit breakers the condition parameters and sub-condition parameters have been selected as follows:

- Operating mechanism
    - Lubrication
    - Linkage
    - Cabinet
    - Operating type (as a multiplier)
- Contact performance
    - Closing timing
    - Trip timing
    - Contact resistance
    - Contact over-travel
    - Arcing contact
- Arc Extinction
    - Heater
    - Leakage
    - Interrupter
    - Oil DGA
- Insulation
    - Power factor
    - Oil quality (applicable to oil breakers only)
    - Insulation
- Service record
    - Operating counter
    - Age

For circuit breakers, the operating mechanism, contact performance, arc extinction and service record sub-condition parameter inputs were supplied by data and/or corrective maintenance records obtained from an electronic maintenance database(s) whereas much of the insulation sub-condition parameter inputs were supplied by actual test data. Additional factors such as obsolescence, known design flaws or performance issues were also accounted for in the AHI.

HVDC System Breakers:

The equipment condition evaluation involved the review and assessment of the following criteria:

- Equipment performance information from the following sources:
  - Electronic defective work order information and notes contained within AMPS
  - Reliability information from Electrical Power Research Institute (EPRI) and others
  - Paper maintenance documentation from site
- Maintenance records from the following sources:
  - Electronic maintenance work order information and notes contained within AMPS
  - Paper maintenance documentation from site
  - Insulation test results in electronic and paper form
- Evaluation of Equipment Obsolescence
  - Equipment age
  - Spare parts availability from the following sources:
    - AMPS stores inventory
    - Original equipment manufacturer
  - Technical Support availability from the following sources:
    - Internal staff
    - Original equipment manufacturer
    - Other equipment support companies

The breakers have a useful life expectancy of 40-65 years

Protection Relays

Health Index Formulation

The methodology for protection relays, be it electromechanical or solid state, was completed in a very similar manner to the approach taken by the third party consultant with the exception that the model was simplified given probability of failure curves were not developed or readily available.
For protection relays the condition parameters and sub-condition parameters have been selected as follows:

- Age
- Manufacturer support
- Spare parts
- Maintenance performance

For protection relays, the condition parameter inputs were supplied by data and/or corrective maintenance records obtained from an electronic maintenance database(s). Additional factors such as known obsolescence and performance issues were also accounted for in the AHI.

Transmission System Battery Banks

Health Index Formulation

Batteries are an asset that are quite different from most other electrical assets and need to be treated as such. The methodology for battery banks differs somewhat from other assets in that a formula using age, potential failures, functional failures along with appropriate weighting factors is used to establish an AHI. The difference between potential and functional failures is normally a matter of degree; a potential failure requires corrective maintenance but was an issue that, due to regular inspection(s), would have become a functional failure had it not been caught in time. Functional failures can be described as events such as "Fails to regulate voltage" or other such conditions that impact the actual performance of the battery bank should they be called upon for service.

For battery banks the condition parameters and sub-condition parameters have been selected as follows:

- Age
- Past maintenance history including potential and functional failures

For battery banks, the condition parameter inputs were supplied by data and/or corrective maintenance records obtained from an electronic maintenance database(s).

HVDC System Battery Banks:

The equipment condition evaluation involved the review and assessment of the following criteria:

- Visual inspections
- Past test data (if available) (resistance(now)/conductance(before), specific gravities, and voltages)
- Previous performance of batteries if they have been put to use (i.e. AC power loss and batteries were called upon to carry the DC load)
- Past maintenance records

The battery banks have a useful life expectancy of 20 years

Transmission System Steel Structures/Grillage

Due to the nature of steel structures/grillage, their associated foundations combined with available asset data, the methodology differs from that used by the third party consultant. Age was one of two characteristics used for condition assessment of transmission structures, excluding wood structures, and accounts for 20 percent of the condition index. Actual asset condition obtained from Manitoba Hydro's transmission line patrol database was the second characteristic used and accounts for 80 percent of the condition index. Reports reviewed for each line summarize annual visual inspections and note problems such as bent/broken/cracked footings, submerged/sinking/heaving footings, tilted footings, spreads, and bent tower steel.

Transmission System Overhead Conductors

Health Index Formulation

Due to the nature of overhead conductors, the methodology differs from that used by the third party consultant. Age was the primary qualifier used for condition assessment of transmission conductors. Reports from Manitoba Hydro's transmission line patrol database were reviewed for each line and used to validate the condition assigned based on age. These reports summarize annual visual inspections and note problems such as broken strands, bird caging, nicks/scars, and burn marks. For several lines the condition was adjusted to more accurately reflect the maintenance patrol reports.

HVDC System Synchronous Condenser:

The criteria used in evaluating the condition of the synchronous condenser are as follows:

- Age of the asset
- Maintenance history -repairs, leaking, increased tolerances, or additional maintenance impact the score. Discussion with the project manager to determine what additional work was carried out between overhauls.
- Operation performance - review of outages to see if there have been additional outages, or vibration issues.
- Physical Condition- Visual of the exterior for signs of deterioration, review of notes on internal inspection, plus assessments from engineering make up this score.

The synchronous condensers have a useful life expectancy of 65 years. The refurbishment programs, every 15 years, address the major issues found through maintenance, failures and obsolescence. The refurbishment of the unit substantially affects the life expectancy of these units.

HVDC System Shunt Reactor:

The criteria used in evaluating the condition of the shunt reactor are as follows:

- Age of the asset
- Maintenance history – oil byproduct evaluations, repairs, or additional maintenance would reduce the score.
- Operation performance - review of outages and a corresponding reduction in score corresponding with the seriousness of the failures.
- Physical condition- visual of the interior and exterior for signs of deterioration, score is combined from two items. Greater emphasis is placed on the findings during an internal inspection of the unit by the engineers.

The shunt reactors have a useful life of 35 years.

HVDC System Smoothing Reactor:

The criteria used in evaluating the condition of the smoothing reactor are as follows:

- Age of the asset
- Maintenance history - repairs, or additional maintenance would reduce the score.
- Operation performance - review of outages and a corresponding reduction in score for failures.
- Physical condition - visual of the exterior for signs of deterioration

The smoothing reactors have a useful life of 25 years.

HVDC System Converter Transformer:

The criteria used in evaluating the condition of the converter transformer are as follows:

- Oil Samples - review of dielectric strength, moisture and combustible gas generation.
- Power Factor - review of capacitance bridge tests and excitation current
- Winding DC Resistance - considers the test results from resistance tests, turn to turn ratio test and SFRA tests
- Operation and maintenance - review of outages, maintenance history, and a corresponding reduction in score for failures.
- Internal inspections of units looking for core shifting, missing blocks. External inspections looking for weld cracks, leaks, and cracked porcelain. The engineer's internal inspection is more heavily weighted than the exterior inspection.
- Age of the unit

The converter transformer has a useful life of 40-50 years.

HVDC System Valve Group

The criteria used in evaluating the condition of the valve group are as follows:

- Age of unit
- Maintenance history - repairs, unavailability of parts or additional maintenance would reduce the score
- Operational performance - review of outages to see if there have been additional outages, and a corresponding reduction in score for failures
- Physical Condition - visual of the exterior for signs of deterioration, broken fasteners, leaks in piping, loss of support for cooling pipes, and optical fibres.

The valve group has a useful life of 25 years.

Valve groups in Bipole 2 are all of the same generation and are all showing similar wear characteristics. Bipole 1 has two different valve group types in Pole 1 and Pole 2 and are showing different issues. Within Pole 1 there are differences in the issues found, which makes direct comparisons of the valve groups difficult. This therefore requires individual assessments of the valve groups to determine their respective conditions.

The failure of a valve group is a gradual process as various components wear out, or fail and require custom made solutions to restore to service. Manufacturers only continue supporting a valve group design for a limited time. Eventually there are too many items to have custom designed, and built causing the replacement of the valve group.

HVDC System Valve Group Cooling:

The criteria used in evaluating the condition of the valve group cooling are as follows:

- Age of the asset
- Maintenance history – repairs, or additional maintenance would reduce the score
- Operation performance – review of outages, reduced cooling capacity, interventions for repair and clearing of fins with custom cleaners are considered and a corresponding reduction in score applied.
- Physical condition – visual inspection of the exterior for signs of deterioration (fins bent, deposits on coolers that can no longer be cleaned, rust, leaks, etc.)

The valve cooling has a useful life of 20 years.

The coolers seldom fail in a destructive manner. They usually slowly deteriorate losing capacity due to blockages, fin damage and buildup on the fins that no longer comes off. At some point this results in a reduction of power output, and loss of revenue. When this point is imminent the coolers are specified for replacement.

The failure of a valve group is a gradual process as various components wear out, or fail and require custom made solutions to restore to service. Manufacturers only continue supporting a valve group design for a limited time. Eventually there are too many items to have custom designed, and built causing the replacement of the valve group.

Appendix D: Distribution Detailed Methodology

Asset Condition Assessment Methodology

Distribution Asset Maintenance has performed a thorough review of the eight key assets to gain a better understanding of the current demands on the system and how they will impact performance over the next 20 years. This study took into account asset demographics, degradation mechanisms, inspection and maintenance, asset health, risk and valuation so that potential investment gaps could be identified and addressed.

The health indexes of the eight key assets were based upon the following:

- Asset Age
- Asset Type
- Inspection Programs
- Maintenance Programs
- Historical Data

These values are used to determine an overall asset health index, which is as follows:

- Very poor = Beyond acceptable level of risk and replacement is required (Condition Index 0 -1.49)
- Poor = Manageable level of risk; May replace asset(s) at this level if criticality assessment indicates risk needs to be mitigated or if a business case provides justification (approaching or past expected end of life) (Condition Index 1.5- 3.49)
- Fair = Long term service without notable measures of degradation (still in its useful part of its life) (Condition Index 3.5 – 4.99)
- Good = Midterm service without notable measures of degradation (in the prime of its useful life) (Condition Index 5 – 8.49)
- Very Good = Like new operating at expected measure of performance (early in its life) (Condition Index 8.5 -10)

Circuit Breakers:

Please refer to the Circuit Breaker Health Index Formulation description, which can be found in Appendix D: Transmission Detailed Methodology.

Station Transformers:

Please refer to the Station Transformer Health Index Formulation description, which can be found in Appendix D: Transmission Detailed Methodology.

Overhead Transformers:

The assessment of overhead transformers is based on the following criteria:

- Age
- Regularly Scheduled Visual Inspections
- Regularly Scheduled Grounding System Inspection

Overhead transformers consistently outlast the pole structures that support them. Generally, they are replaced before the end of the expected useful life due to various system improvement projects (e.g. voltage conversions, transformer capacity upgrades, line refurbishments). As a result of this, the AHI is based primarily on age.

Visual inspections are required to be completed once every six years for every overhead distribution circuit. As part of these inspections, operational staff examines the transformer installation and note any signs of potential problems, such as oil leakage, overloading, corrosion and tree contacts.

Overhead transformers have a useful life expectancy of 75 years.

Padmounted Transformers:

The assessment of padmounted transformers is based on the following criteria:

- Age
- Regularly Scheduled Visual Security Assessment
- Regularly Scheduled Maintenance Inspection

Padmounted transformers are replaced at the end of the expected useful life resulting from regularly scheduled condition assessments. As a result of this, the AHI is based primarily on age.

Underground transformers have a yearly security check to ensure they are locked, not leaning severely, accessible, and no large oil leaks are visible externally. They also have a maintenance inspection done on a 6 year cycle where they are opened, cleaned, and thoroughly inspected.

Padmounted transformers have a useful life expectancy of 50 years.

Overhead Primary Conductor:

The assessment of overhead primary conductor is based on the following criteria:

- Age
- Conductor Type
- Regularly Scheduled Visual Inspections

Overhead primary conductors have a very low rate of failure and consistently outlive the structures that support them. Replacement of these assets generally take place before the end of the expected useful life due to performance related issues (e.g. demand exceeds conductor current carrying capacity, conductor impedance caused poor voltage profiles). As a result of this, the AHI is based primarily on the capacity of the conductor type; however, the age of the line is also taken into consideration.

Although specific testing is not performed on distribution conductors, visual inspections do occur on a regular basis. Visual inspections are required to be completed once every six years for every overhead circuit.

Overhead primary conductors have a useful life expectancy of 100 years.

Manholes:

The assessment of manholes is based on the following criteria:

- Age
- Construction Method (built in place, pre-fabricated)
- Construction Material (concrete, brick, clay tile)
- Regularly Scheduled Visual Inspections

The AHI of the manhole population is based upon a 2012 survey of 850 manholes within the downtown region of Winnipeg. The results of the study were then extrapolated over the entire population of manholes in Manitoba to determine the overall AHI.

Manhole inspections are completed on a three year cycle by operational staff. A visual check on the structural integrity of the manhole structure is performed, as well as an infra-red inspection of all electrical connections within the vault. The visual check includes the manhole cover, cover ring, collar, walls, ceiling, and floor.

Manholes have a useful life expectancy of approximately 80 years.

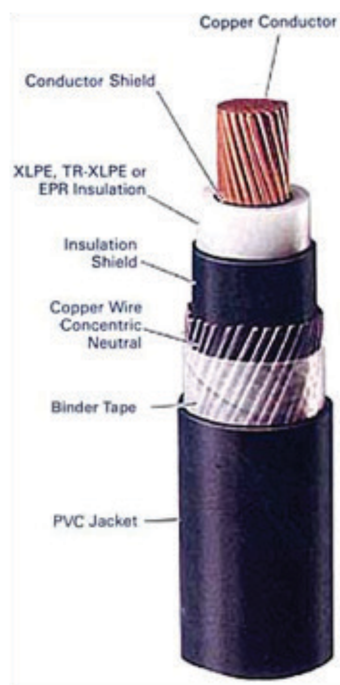
Underground Cables::

The assessment of underground cables is based on the following criteria:

- Age
- Cable Type (PILC, RINJ/RIPVCJ, XLPE/TRXLPE)
- Cable Manufacturer

Due to the extreme difficulty in inspecting buried cables, there is currently no regularly scheduled inspection program in place that is used to evaluate the health of these assets. As a result, the AHI of the underground cables are determined by the age of each cable type.

Underground cables have a useful life expectancy of approximately 30 – 70 years, depending on the cable type.



Ductlines:

The assessment of ductlines is based on the following criteria:

- Age
- Construction Material (PVC pipe, cast iron pipe, ceramic pipe)
- Visual Inspections

Ductlines have a very low rate of failure and consistently outlive the manholes and structures which they are connected to. Replacement or refurbishment of these assets generally take place only when associated work (i.e. manhole or station rebuilds) is scheduled within the area in order to take advantage of reduced construction costs.

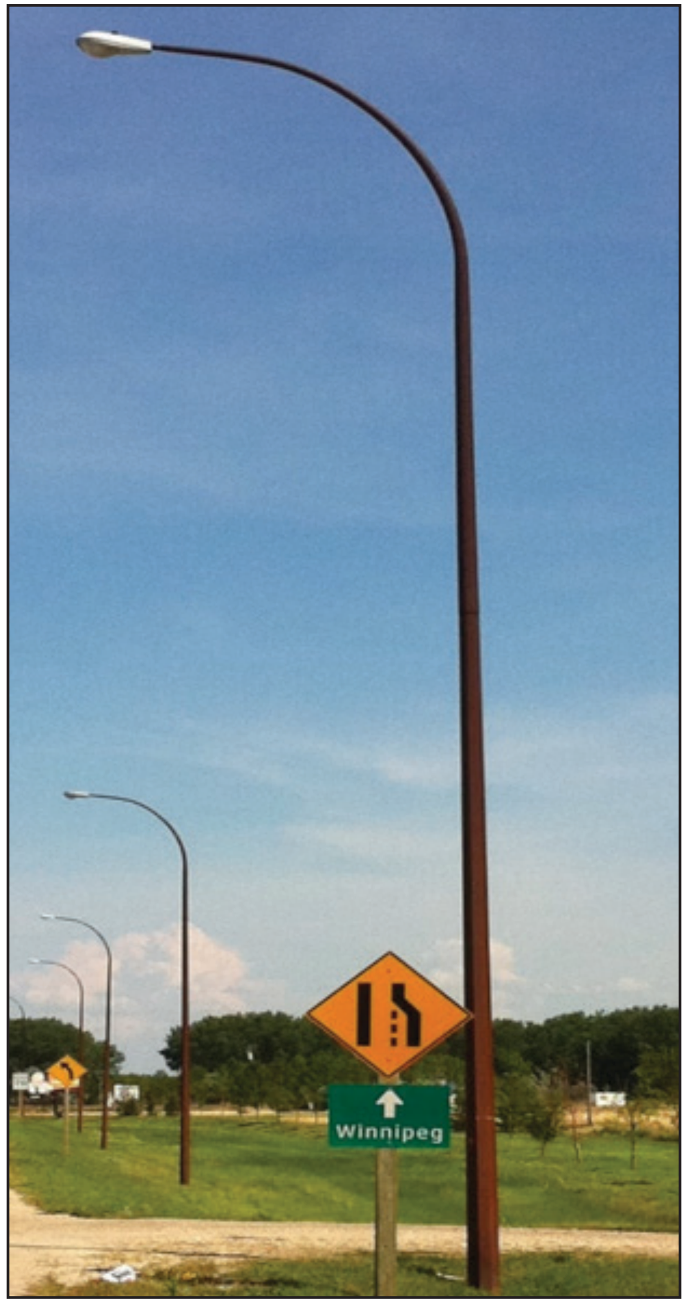
Although specific testing is not performed on duct lines, visual inspections do occur as part of regularly scheduled manhole inspections. As part of these inspections, operational staff will note if the duct line is exhibiting any visible signs of shifting or individual duct segments are collapsing or crumbling.

Manholes have a useful life expectancy of approximately 100 years.

Street Lights:

The assessment of street lights is based on the following criteria:

- Age
- Regularly Scheduled Visual Inspections
- Installation method (concrete pile, direct bury, power screw)



The AHI is based upon the DMPS reports of the previous four years and extrapolated over the entire street light population.

City of Winnipeg streetlights are scheduled for inspection once every four years. Standards are inspected by the Streetlight Maintenance and Underground Inspection Section. Outside the City of Winnipeg inspections are organized by the local CSC.

Street lights have a useful life expectancy of approximately 50 – 70 years, depending on the street light installation type.

Wood Poles:

The assessment of wood pole is based on the following criteria:

- Age
- Integrated Pole Maintenance Program (Regularly Scheduled Inspection/ Evaluation)
- Regularly Scheduled Visual Inspections

The AHI of wood poles is based upon the summary of the IPM program, as well as age.

In 1989, Manitoba Hydro implemented the Integrated Pole Maintenance program (IPM). The program is a designed to provide an accurate assessment of our wood poles on a 15 year cycle. Each pole receives a thorough inspection, strength evaluation, remedial treatments as required and attribute information is collected electronically. These remedial treatments are designed to provide the poles with added protection internally and externally to extend their service life.

Wood poles have a useful life expectancy of 75 years.

Appendix E: Endnotes

[1] Expected life is dependent on asset type: Mechanical (80-90 years), Analog/Digital (50/25 years).

[2] Expected life is dependent on asset type: Mechanical (100-125 years), Analog (45-55 years) and Digital (20-25 years).

[3] The expected life is dependent on loading and service type.

[4] Four (4) transmission system breakers have been replaced over the last ten years due to in service failures and nineteen (19) have been replaced or retired for system development or economic reasons.

[5] Reasons for replacement:

- 107 - 4kV and 12kV breakers were replaced due to safety and reliability concerns in early 2000s.
- All 46kV breakers were replaced.
- 43 of Dorsey's breakers upgraded in the early 90s due to insufficient capacity.
- One 500kV breaker replaced in 2010 due to condition,
- 15 of Dorsey's 230kV breakers are to be replaced by 2017 due to insufficient capacity.
- 31- 138kV breakers at Radisson are to be replaced around 2025 due to insufficient capacity.

[6] Costing of the breakers appears low because these numbers include 4, 12 and 46KV breakers.

[7] Station Battery Capacity & System Reliability Increase Program included 138 battery replacement projects since 2005. This program is expected to conclude in 2017.

[8] The expected life is dependent on loading and service type.

[9] Seven (7) transmission system transformers have been replaced over the last ten years due to in service failures and ten (10) have been removed from service as part of the Pointe Du Bois Transmission Redevelopment and Transcona East Station Projects.

[10] The expected life is dependent on loading and service type.

[11] Expected life is very dependent on device technology. Electromechanical devices have longer expected service performance than electronic devices. A key factor in end of life expectancy is obsolescence. Expected end of life is extended by ensuring adequate spare relays are retained after protection system upgrades.

[12] Three major programs have replaced 52 obsolete line teleprotection systems since 2005. The number of additional protection relay replacements or retirements completed as part of system improvement capital projects was not determined for this report.

[13] Close to 700 steel structures have been removed from service and/or replaced with new transmission infrastructure over the last 10 years. Additional partial structure replacements (e.g. footing replacements) are not reflected in this number.

[14] Slightly over 700 wood pole structures have been removed from service and/or replaced with new transmission infrastructure over the last 10 years. Additional partial structure replacements (e.g. individual poles or cross arms) are not reflected in this number.

[15] Approximately 350 km of three phase conductor has been removed from service and/or replaced with new transmission infrastructure over the last 10 years.

[16] Refurbishments to date have kept all original units in service.

[17] Refurbished one unit after failure, and it is retained as a spare.

[18] All units replaced in last four years when condition of old units dictated. New units are air core. This style has performed well in the filter positions, but has not been used in the smoothing reactor role before. Expected life and turn over are an estimate at present.

[19] The existing turnover rate is based upon the past 10 years of station breaker replacements. Due to a recognized need to increase system capacity as a result of customer demand, it is expected that station upgrade and replacement rates will dramatically increase in the near future which may result in reduced turnover rates.

[20] The expected life is dependent on loading and service type.

[21] The existing turnover rate is based upon the past 10 years of station transformers replacements. Due to a recognized need to increase system capacity as a result of customer demand, it is expected that station upgrade and replacement rates will dramatically increase in the near future which may result in reduced turnover rates.

[22] Expected life is dependent upon cable type: PILC (60-70 years), RINJ/RIPVCJ (30-40 years), XLPE/TRXLPE (40-50 years).

[23] Currently, no ductline replacement program exists as the life of the asset consistently outlasts that of the manholes they are connected to. Ductlines are rehabilitated or replaced when associated work in performed within the area in order to take advantage of the reduced costs of construction.

[24] Currently, no conductor replacement program exists as the life of the asset consistently outlasts that of the pole structure supporting it. Due to an increase in system capacity resulting from customer demand, overhead conductors are replaced as a result of capacity upgrades.

[25] Expected life is dependent upon installation method: direct install/power screw (50-60 years), concrete base (60-70 years).

MANITOBA HYDRO
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FINANCIAL RESULTS & FORECASTS

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Appendices

5.1 Manitoba Hydro-Electric Board Annual Report Year Ended March 31, 2014

5.2 Manitoba Hydro-Electric Board Quarterly Report Ended June 30, 2014

5.3 Manitoba Hydro-Electric Board Quarterly Report Ended September 30, 2014

5.4 International Financial Reporting Standards Status Update Report

5.5 Operating, Maintenance, & Administrative Expense

5.6 Depreciation Rates & Depreciation Study

5.7 Net Impact of Accounting Policy & Estimate Changes

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

FINANCIAL RESULTS & FORECASTS

5.0 OVERVIEW

Tab 5 provides explanations of the actual and forecast revenues and expenses related to Manitoba Hydro's Electric operations for 2012/13 to 2016/17, and outlines the significant year over year changes. Section 5.1 provides a summary of Manitoba Hydro's financial results and forecasts for 2012/13 to 2016/17, and Sections 5.2 to 5.13 discuss the revenue and cost components for 2012/13 to 2016/17. Section 5.14 outlines a number of initiatives that Manitoba Hydro is undertaking to reduce costs and ease pressures on financial results and rates.

The key conclusions with respect to Tab 5 are:

1. The requirement for the proposed rate increases are primarily being driven by the increased finance expense, depreciation and amortization expense and capital taxes associated with investment in new assets and reinvestment in existing assets.

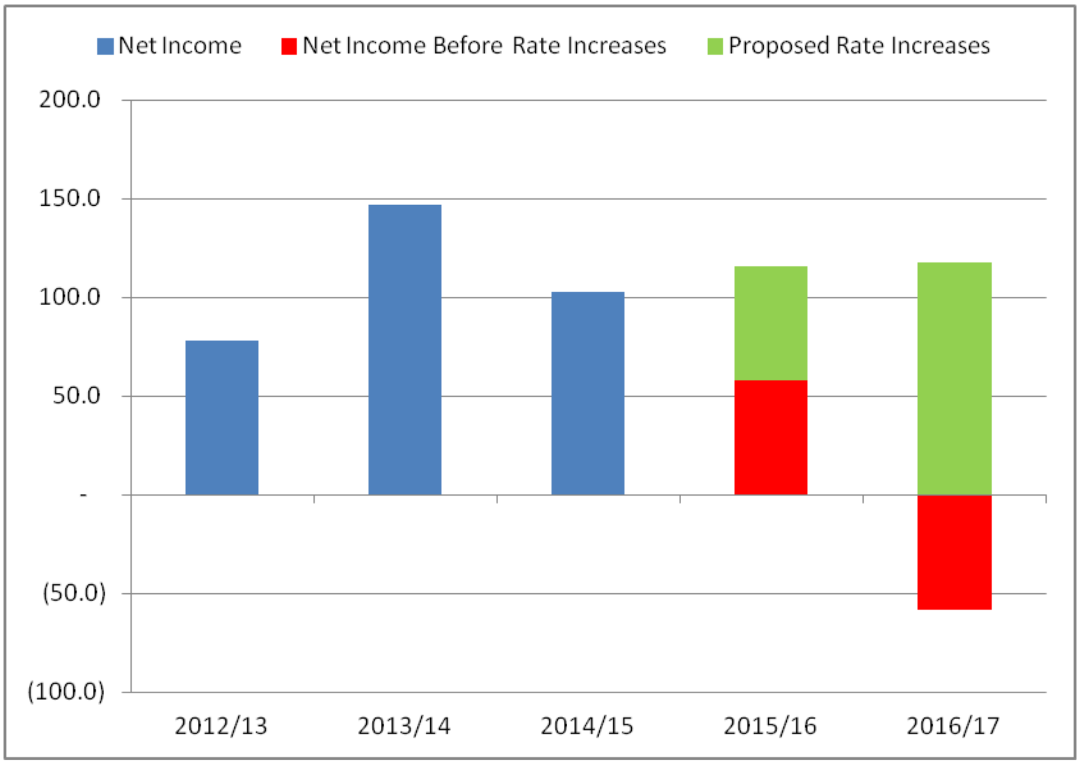
2. Manitoba Hydro is committed to effectively controlling its OM&A costs and has recently completed an extensive review of its staff compliment and is undertaking a number of initiatives across the Business Unit's to maintain OM&A cost increases at 1%, which is below inflationary levels (excluding accounting changes that impact OM&A).

3. While there are a number of prospective accounting changes being made for financial reporting purposes between 2014/15 and 2015/16 that will increase OM&A and decrease Depreciation and Amortization, these changes offset each other and are not driving the need for rate increases.

5.1 SUMMARY OF FINANCIAL RESULTS & FORECAST

Figure 5.1 provides a summary of actual and forecast net income for electric operations (excluding subsidiary operations) for 2012/13 to 2016/17. For 2015/16 and 2016/17, the red bars show Manitoba Hydro's net income/loss without the proposed rate increases and the green bars show the projected net income including the proposed rate increases.

Figure 5.1 Net income



The following schedule provides a breakdown of the Statement of Income.

MANITOBA HYDRO **Schedule 5.1.0**
STATEMENT OF INCOME **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Revenue					
General Consumers	1 341 011	1 424 126	1 436 742	1 454 388	1 460 247
Bipole III Reserve	-	(18 826)	(29 997)	(32 360)	(33 773)
Extraprovincial	352 633	439 182	408 892	434 157	449 738
Other	29 854	21 758	15 223	13 870	13 999
Total Revenue Excluding rate increases	$ 1 723 497	$ 1 866 241	$ 1 830 860	$ 1 870 055	$ 1 890 211
Expenses					
Operating, Maintenance and Administrative	462 952	480 717	485 755	541 740	551 675
Finance Expense	452 367	435 402	494 852	510 423	547 520
Depreciation and Amortization	391 923	410 834	404 590	400 866	422 404
Water Rentals and Assessments	117 864	125 517	124 469	122 847	112 167
Fuel and Power Purchased	133 292	177 113	134 189	130 432	190 933
Capital and Other Taxes	86 399	96 750	99 170	107 156	120 534
Corporate Allocation	9 074	9 074	8 659	8 393	8 396
Other Expenses	4 750	6 294	2 311	2 355	2 402
Total Expenses	1 658 621	1 741 701	1 753 995	1 824 211	1 956 031
Non-controlling Interest*	13 160	22 005	25 452	12 126	7 580
Net Income before rate increases	$ 78 036	$ 146 545	$ 102 317	$ 57 970	$ (58 241)
Proposed Rate Increases (3.95% April 1, 2015 & 3.95% April 1, 2016)				57 377	117 638
Net income including rate increases	$ 78 036	$ 146 545	$ 102 317	$ 115 347	$ 59 397
Year over year $ change		$ 68 509	$ (44 228)	$ 13 030	$ (55 949)

*Non-controlling interest represents NCN's share of the net income/loss from WPLP.

2013/14 Actual vs. 2012/13 Actual

Net income from Electric operations increased in 2013/14 primarily as a result of higher extraprovincial revenue mainly due to increased generation from stations on the Nelson River due to higher flows, as well as higher general consumers revenue mainly due to colder winter weather, a rate increase and customer growth.

The increase in revenue was partially offset by an increase in fuel and power purchased primarily due to higher purchased volumes from the colder winter weather, an increase in depreciation and amortization expense attributable to new additions to plant and equipment coming into service, and an increase in operating, maintenance and administrative expense (OM&A) primarily due to higher pension and benefit costs related to changes in discount and mortality rates and greater employer contributions.

2014/15 Forecast vs. 2013/14 Actual

Net income from Electric operations is forecast to decrease in 2014/15 primarily as a result of lower extraprovincial revenue from lower US sales volumes largely due to transmission outages that restricted exports on the US transmission line during October and November 2014 and an increase in finance expense due to higher net interest on debt as assets go in-service and lower realized gains on the sinking fund and U.S. debt.

These reductions to net income are partially offset by lower fuel and power purchased primarily due to lower purchased volumes due to the assumption of normal winter weather and a year-over-year projected increase in hydraulic generation during the winter period .

2015/16 Forecast vs. 2014/15 Forecast

Net income from Electric operations is forecast to increase in 2015/16 primarily as a result of an increase in general consumers revenue mainly due to the proposed 3.95% rate increase effective April 1, 2015, as well as an increase in extraprovincial revenue mainly due to higher export prices.

The increase in revenue is partially offset by an increase in finance expense primarily due to new long term debt issues to finance the Corporation’s capital investment requirements, as well as interest rates that are projected to rise to more normalized levels, and increases in depreciation expense as a result of plant assets going into service. The net impact of accounting policy changes as a result of the transition to IFRS results in an overall reduction to net income. Please see Appendix 5.7 for additional information on the impact of accounting policy and estimate changes.

2016/17 Forecast vs. 2015/16 Forecast

Net income from Electric operations is forecast to decrease in 2016/17 primarily as a result of increases in the volumes of US off-peak purchases and increased thermal costs due to the assumption of average water flows in 2016/17 compared to median water flows in 2015/16 , an increase in finance expense primarily due to higher debt levels to finance the Corporation’s capital investment requirements as well as interest rates that are projected to rise to more normalized levels and an increase in depreciation and amortization as well as capital taxes primarily due to increased plant investment.

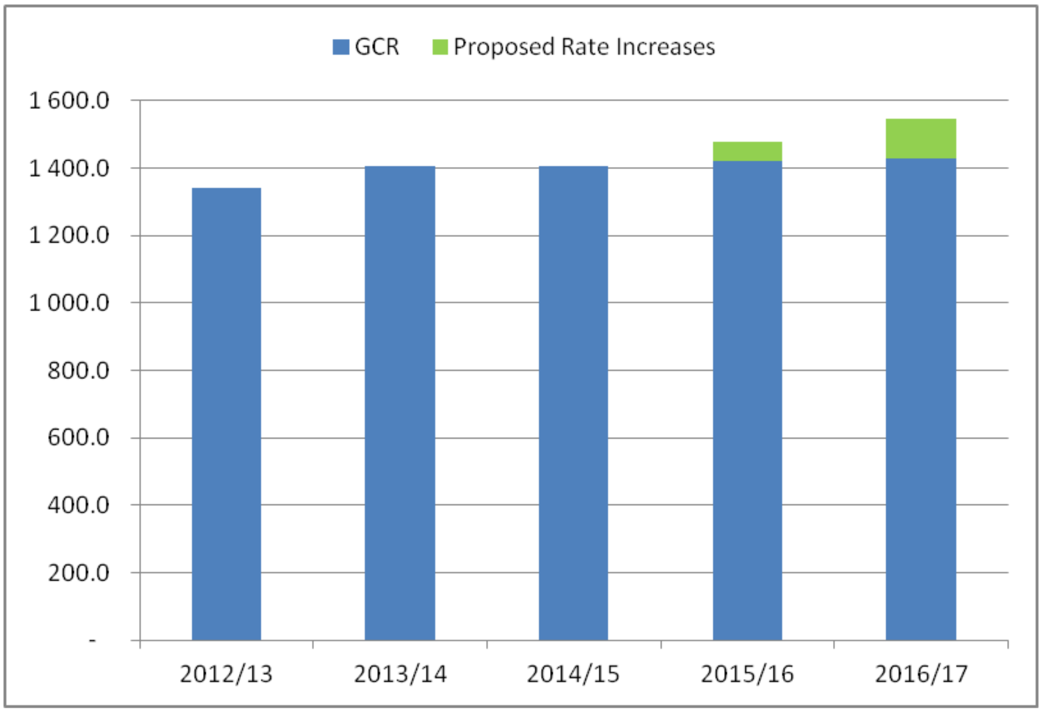
These reductions to net income are partially offset by an increase in general consumers revenue mainly due to the proposed 3.95% rate increase effective April 1, 2016, as well as an increase in extraprovincial revenue mainly due to a projected increase in export prices for Dependable and Opportunity Sales in 2016/17.

The following sections review each component of the Statement of Income. A description of each component, the year over year changes explanation and the detailed schedule is provided.

5.2 GENERAL CONSUMERS REVENUE

General consumers revenue ("GCR") is comprised of electricity sales to Manitoba Hydro's domestic customers as well as late payment charges. Customers are aggregated in two major rate classes – Residential and General Service (Commercial and Industrial customers and Area and Roadway Lighting). For 2015/16 and 2016/17, the blue bar in Figure 5.2 shows the GCR generated from existing rates and the green bar shows the additional revenues generated from the proposed rate increases.

Figure 5.2 General Consumers Revenue



The following schedule provides a breakdown of GCR.

MANITOBA HYDRO **Schedule 5.1.1**
GENERAL CONSUMERS REVENUE **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Residential	$ 562 959	$ 614 156	$ 597 916	$ 605 105	$ 612 761
General Service	778 052	809 971	838 826	849 283	847 486
Bipole III Reserve Account		(18 826)	(29 997)	(32 360)	(33 773)
Total Revenue excluding rate increases	1 341 011	1 405 301	1 406 745	1 422 028	1 426 474
Additional General Consumers Revenue*				57 377	117 638
Total Revenue including rate increases	$ 1 341 011	$ 1 405 301	$ 1 406 745	$ 1 479 405	$ 1 544 112
Year over year $ change		$ 64 290	$ 1 444	$ 72 660	$ 64 707
Year over year % change		4.8%	0.1%	5.2%	4.4%

* Additional General Consumers Revenue - 2015/16 and 2016/17 reflect rate increases of 3.95%

The Residential class is comprised of all housing types (single detached, duplexes, triplexes, etc.) and also includes individual metered apartment blocks, seasonal cottages and farm residences.

The General Service ("GS") class is comprised of commercial and industrial customers in the General Service Small, Medium and Large rate categories as well as Area and Roadway Lighting. Customers are classed as a GS Small if their connected load is less than 200 kV.A and their transformation is owned by Manitoba Hydro. Customers classed as GS Medium have connected loads which exceed 200 kV.A and whose transformation is also owned by Manitoba Hydro. GS Large customers have loads which typically exceed 2000 kV.A and who own their own transformation. The GS Large class is further divided into three sub-classes based on the voltage used to serve the customer (750V-30 kV, 30 kV-100 kV and >100 kV). The Area and Roadway Lighting class is comprised of all street lights and sentinel lights which may be publically or privately owned or rented.

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is primarily due to higher consumption from colder winter weather, a rate increase, as well as customer growth. The PUB approved a rate increase of 3.5% effective May 1, 2013. The PUB directed that 2.0% of the 3.5% increase be included in general revenue and that 1.5% be set aside to mitigate rate increases when Bipole III is placed into service.

2014/15 Forecast vs. 2013/14 Actual

The forecast 2014/15 increase is primarily due to the 2.75% rate increase approved by the PUB on an interim basis effective May 1, 2014. The PUB directed that 2.0% of the 2.75% increase be included in general revenue and 0.75% be set aside to mitigate rate increases when Bipole III is placed into service. The revenue increase is partially offset by the assumption of normal weather conditions for 2014/15.

2015/16 Forecast vs. 2014/15 Forecast

The forecast 2015/16 increase is primarily due to the additional revenue associated with the proposed 3.95% rate increase effective April 1, 2015 as well as a 1.0% increase in energy consumption primarily due to growth in the Residential and General Service Large sectors.

2016/17 Forecast vs. 2015/16 Forecast

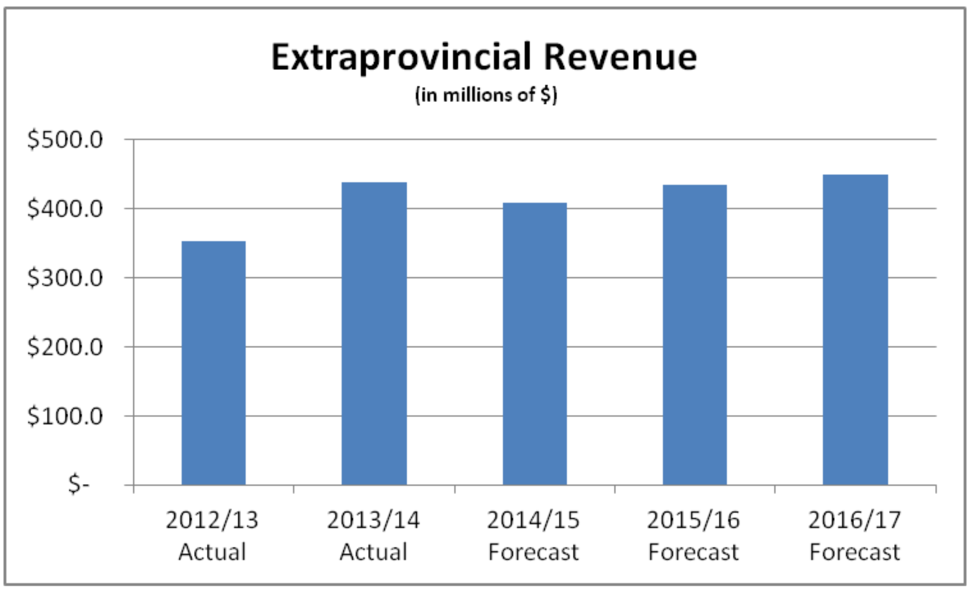
The forecast 2016/17 increase is primarily due to the additional revenue associated with the proposed 3.95% rate increase effective April 1, 2016 as well as load growth in the Residential sector. These increases are partially offset by a reduction in load in the General Service sector due to a Top Consumer phasing out a significant portion of their operation.

5.3 EXTRAPROVINCIAL REVENUE

Extraprovincial Revenue includes revenues from Canadian and US export sales as well as revenues from other associated export market activities such as merchant sales, transmission credits and renewable energy certificates.

Forecast Extraprovincial Revenues for 2014/15 are based on current storage conditions and expected inflows, assuming normal precipitation conditions for the remainder of the fiscal year. Revenues for 2015/16 are based on storage conditions carried forward from the prior fiscal year and median inflows. For the subsequent years, the projections are determined by averaging the revenues using the full range of experienced flow conditions.

Figure 5.3 Extraprovincial Revenue



Please see the following schedule for a breakdown of Extraprovincial Revenue.

MANITOBA HYDRO **Schedule 5.1.2**
EXTRAPROVINCIAL REVENUE **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Canadian Sales	33 353	20 392	28 748	16 104	43 626
Other Sales	122	(40)	(54)	-	-
Canadian	33 475	20 352	28 694	16 104	43 626
US Sales	284 819	355 306	343 003	380 033	379 506
Other Sales	4 973	8 722	6 468	5 688	572
Transmission Credits	18 307	18 021	17 443	22 140	23 841
Renewable Energy Certificates	1 942	3 494	3 045	2 299	2 193
US	310 042	385 543	369 959	410 160	406 112
Merchant (IESO & MISO)*	9 116	33 287	10 239	7 893	-
Total Extraprovincial Revenue	$ 352 633	$ 439 182	$ 408 892	$ 434 157	$ 449 738
Year over year $ change		$ 86 549	$ (30 290)	$ 25 265	$ 15 581
Year over year % change		24.5%	-6.9%	6.2%	3.6%

*IESO = Independent Electricity Systems Operator and MISO = Midcontinent Independent System Operator

Please see the following for a description of Extraprovincial Revenue components:

Canadian and US Sales include both Dependable and Opportunity Sales.

Dependable sales are export contracts sourced from Manitoba Hydro’s dependable energy resources. Dependable energy resources are energy supplies assumed to be available in the event that the lowest recorded water supply conditions are repeated. Dependable sales involve capacity and energy commitments, are negotiated at least one year in advance of delivery, and have duration of greater than six months.

Sales not identified as Dependable are called Opportunity sales and can be sourced from non-dependable resources or uncommitted dependable resources:

- Opportunity (Bilateral) – Sales negotiated with a purchasing party and documented by contract or recorded exchange. The duration of delivery for these sales generally does not exceed 6 months, and can be as short as one-hour. Opportunity Bilateral sales can include the sale of capacity and/or energy.

- Opportunity (Day Ahead or Real Time Markets) – Export sales transactions in a market operated by an independent system operator for the purchase and sale of power related products for the next operating day ('Day Ahead') or during the operating day ('Real Time').

Merchant transactions represent arbitrage opportunities and are unrelated to Manitoba Hydro generation. These include physical purchases of power from one market for re-sale to another market.

Other Sales include miscellaneous revenues derived from market activities such as the sale of ancillary services into the Midcontinent Independent System Operator ("MISO") market and congestion management with the Ontario market.

Transmission Credits refer to revenues received for the use of Manitoba Hydro's transmission system. Manitoba Hydro' Open Access Transmission Tariff defines the fees for use of its transmission system. The MISO administers collection of these fees on behalf of Manitoba Hydro, which is why they are reported as US revenues.

Renewable Energy Certificates are revenues received mainly from the sale of environmental attributes acquired by Manitoba Hydro through power purchase agreements with wind generation suppliers in Manitoba.

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase reflects higher US sales volumes largely made possible by increased generation from stations on the Nelson River due to higher flows. Hydraulic generation was also higher in 2013/14 because the Wuskwatim Generating Station was in service for the entire year. Export revenues were also favourably impacted by an increase in merchant sales, higher market prices, and favourable foreign exchange rates on revenues from US sales.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast decrease reflects lower US sales volumes largely due to transmission outages that restricted exports on the US transmission line during October and November 2014. Merchant sales are projected to be lower as Manitoba Hydro does not expect to have the same level of arbitrage opportunities between markets as was experienced in 2013/14. These decreases were partially offset by higher foreign exchange rates affecting revenues from US sales.

2015/16 Forecast vs. 2014/15 Forecast

The 2015/16 forecasted increase reflects higher export prices and a projected increase in foreign exchange rates on US sales. This increase is partially offset by lower Canadian sales volumes due to reduced participation in the IESO market and an expected decrease in merchant sales projected for 2015/16 due to reduced arbitrage opportunities between markets.

2016/17 Forecast vs. 2015/16 Forecast

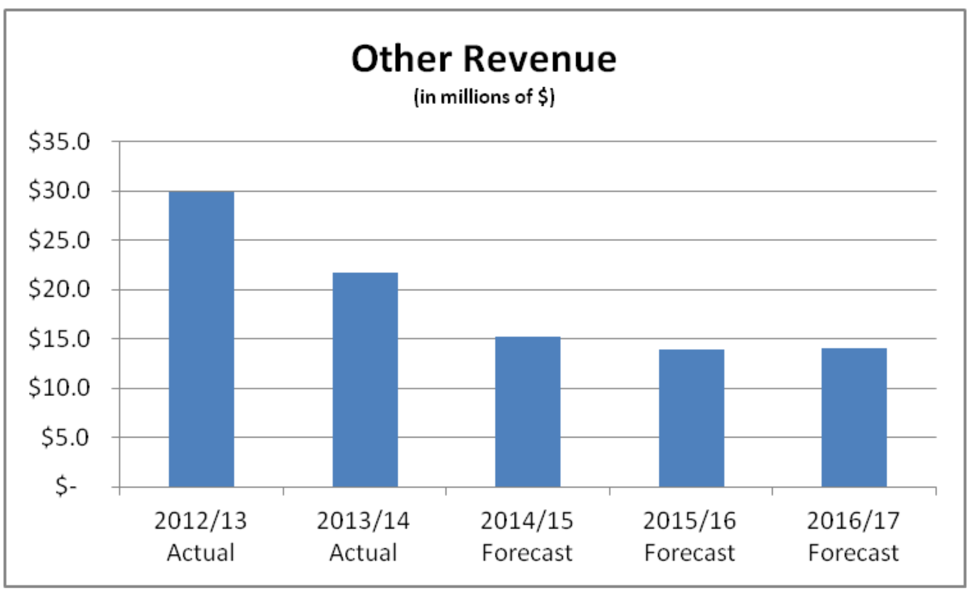
The 2016/17 forecasted increase is primarily due to an increase in prices of Dependable and Opportunity Sales. There are also additional firm export contract sales effective in 2016/17, further increasing the total export revenue compared to 2015/16. This includes the SaskPower 25-megawatt sale which is in effect for its first full year in 2016/17, increasing Canadian sales over 2015/16.

5.4 OTHER REVENUE

Other Revenue includes a variety of different revenue items, with the most significant items being:

- Joint Use contracts representing the net rental revenue between Manitoba Hydro and MTS, Cable TV and other utilities. Net revenue is the difference between gross revenue (attachments on Manitoba Hydro property) and gross billings (Manitoba Hydro attachments on external party property).
- Third party revenues where there is a provision of services for the use/rental of Manitoba Hydro owned assets.
- Revenues received for work the Corporation undertakes on customer owned plant on a fee-for-service basis.
- Electrical inspections performed by Manitoba Hydro on customer owned facilities.
- Gains on sale of land to external parties. Gains are calculated as the sale price less historical acquisition costs and costs of disposal.
- Miscellaneous Other Income which includes income items such as litigation settlements, apprenticeship tax credits, etc.

Figure 5.4 Other Revenue



MANITOBA HYDRO **Schedule 5.1.3**
OTHER REVENUE **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Other Revenue	$ 29 854	$ 21 758	$ 15 223	$ 13 870	$ 13 999
$ Change		$ (8 096)	$ (6 535)	$ (1 353)	$ 129
% Change		-27.1%	-30.0%	-8.9%	0.9%

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 decrease is primarily due to a reduction in gains on sale of land compared to 2012/13 as well as a reduction goods and services sold to outside parties compared to 2012/13.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast decrease is partially due to gains on sale of land that occurred in 2013/14 and are not expected in 2014/15. In addition, there is a reduction in the amount forecast for third party work on customer owned assets.

2015/16 Forecast vs. 2014/15 Forecast

No significant change.

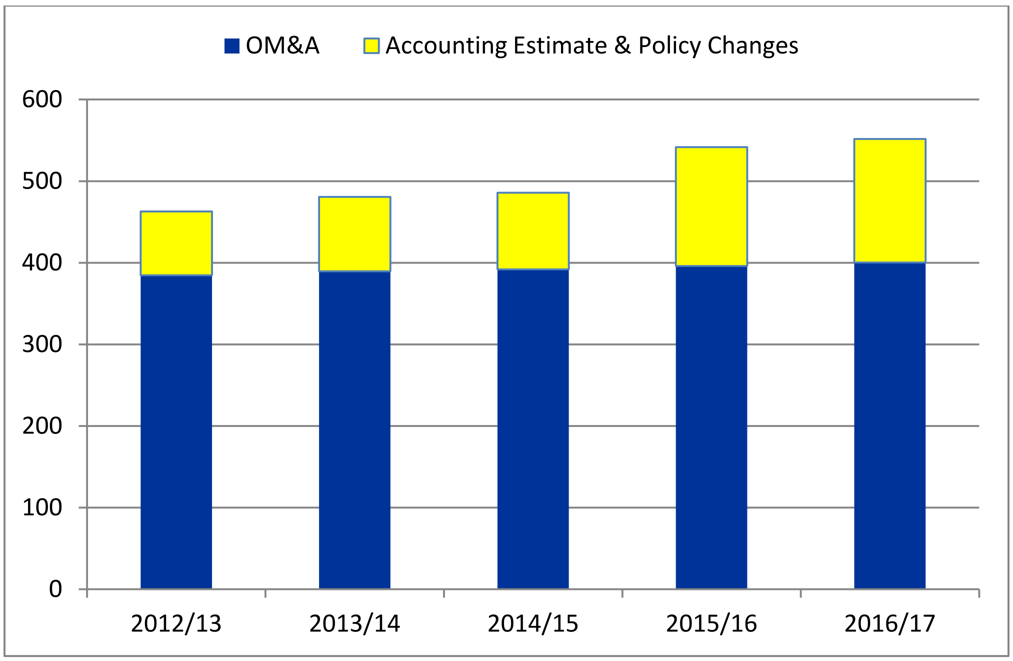
2016/17 Forecast vs. 2015/16 Forecast

No significant change.

5.5 OPERATING, MAINTENANCE & ADMINISTRATIVE

Operating, Maintenance & Administrative (OM&A) Expenses are comprised primarily of labour and benefits, materials, contracted services, and overhead costs associated with operating and maintaining all facilities of the Corporation and providing services to customers. Figure 5.5 provides a summary of OM&A expenses indicating the impact of accounting estimate and policy changes between 2012/13 and 2016/17, which are represented in yellow.

Figure 5.5 Operating, Maintenance & Administrative



The following table provides a breakdown of the OM&A expenses incorporating accounting changes:

MANITOBA HYDRO — **Schedule 5.1.4**
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS — **(000's)**

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)
Wages & Salaries	$ 466 165	$ 480 511	$ 502 692	524 552	533 997	3.5%
Overtime	61 031	62 365	61 709	71 080	73 121	4.8%
Employee Benefits	130 886	157 094	160 592	155 892	158 992	5.3%
Sub-Total	658 082	699 970	724 993	751 523	766 109	
Less: Labour & Benefits Charged to Capital	(215 491)	(234 510)	(256 588)	(282 335)	(287 969)	7.6%
Labour & Benefits Charged to Operations*	442 591	465 460	468 405	469 188	478 140	2.0%
Other Costs						
Employee Safety & Training	4 463	4 596	5 225	5 188	5 175	3.9%
Travel Expenses	31 194	31 915	31 766	31 628	31 634	0.4%
Motor Vehicle	29 516	29 670	29 682	29 699	29 699	0.2%
Materials & Tools	24 806	27 920	26 700	26 090	26 090	1.5%
Consulting & Professional Fees	10 817	14 657	14 349	12 395	12 237	4.6%
Construction & Maintenance Services	16 259	16 775	19 364	18 580	18 580	3.6%
Building & Property Services	25 644	28 978	27 738	27 297	27 297	1.8%
Equipment Maintenance & Rentals	14 680	15 007	16 120	16 191	16 191	2.5%
Consumer Services	5 050	5 277	5 323	5 323	5 323	1.3%
Computer Services	849	678	985	1 020	1 019	7.2%
Collection Costs	4 261	3 125	4 078	4 078	4 078	1.0%
Customer & Public Relations	6 731	5 610	5 334	5 344	5 316	-5.5%
Sponsored Memberships	1 767	1 249	1 764	1 737	1 737	2.6%
Office & Administration	13 874	14 724	15 722	15 721	15 717	3.2%
Communication Systems	1 817	1 963	1 928	1 928	1 928	1.6%
Research & Development Costs	3 372	2 195	2 747	2 747	2 747	-2.4%
Miscellaneous Expense	2 040	1 485	954	900	900	-17.2%
Contingency Planning	-	-	2 594	2 610	2 657	
Operating Expense Recovery	(13 997)	(17 808)	(13 468)	(13 649)	(13 647)	0.0%
Strategic Initiative Funding			870	3 640	6 317	
Sub-Total	183 143	188 016	199 774	198 468	200 994	
Less: Other Costs Charged to Capital	(29 327)	(31 503)	(33 329)	(34 647)	(34 818)	4.4%
Other Costs Charged to Operations*	153 815	156 513	166 444	163 821	166 177	2.0%
Total	**596 406**	**621 973**	**634 849**	**633 009**	**644 317**	2.0%
Less:						
Capitalized Overhead	(69 720)	(74 446)	(81 265)	(24 578)	(24 824)	-13.2%
Operating and Administration Charged to Centra	(63 735)	(66 810)	(67 829)	(66 691)	(67 818)	1.6%
Electric OM&A, including Accounting Changes	**462 952**	**480 717**	**485 755**	**541 740**	**551 675**	4.6%
Less: Accounting Changes	(78 345)	(91 155)	(93 858)	(145 644)	(151 345)	
Electric OM&A, excluding Accounting Changes	**$ 384 607**	**$ 389 562**	**$ 391 897**	**$ 396 096**	**$ 400 330**	1.0%
Year over Year % Change, including Accounting Changes		3.8%	1.0%	11.5%	1.8%	4.6%
Year over Year % Change, excluding Accounting Changes		**1.3%**	**0.6%**	**1.1%**	**1.1%**	**1.0%**

*Includes amounts capitalized through Overhead

The 4.6% average annual growth over the 5 year period is primarily a result of accounting changes. These changes include an increase in pension and benefit costs under CGAAP due to changes in the assumptions used to calculate these costs, such as changes in the discount rate and mortality tables. IFRS changes commence in 2015/16 and primarily impact capitalized overhead costs, which are no longer eligible for capitalization. While accounting changes under both CGAAP and IFRS have impacted OM&A costs, this is fully offset by reductions to depreciation and amortization expense. Please see Appendix 5.7 for more detailed information on the net impact of accounting changes in IFF14.

The average annual growth rate, excluding accounting changes, is 1.0%. The growth of 1.0% reflects higher wages and salaries due to contract settlements, merit and progression of approximately 3% to 4% annually, which is mainly offset by a concerted effort by Manitoba Hydro on cost containment, as further discussed in Section 5.14.

The cost containment strategy focuses on a comprehensive management of staff positions across all Business Units. The corporation continues to review work processes and functions to identify opportunities for the elimination of work no longer deemed essential, to consolidate similar functions where overlap may exist, and to implement changes which reduce costs and increase efficiencies. This review has resulted in a projected reduction of 300 operational EFTs which is discussed further in Appendix 5.5.

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is primarily a result of accounting changes causing higher pension and benefit costs driven by changes in estimates for the discount rate and mortality rates.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast increase is a result of contract wage settlements, which is mainly offset by the Corporation’s cost containment initiatives.

2015/16 Forecast vs. 2014/15 Forecast

The 2015/16 forecast increase is primarily attributable to IFRS accounting changes resulting in the requirement to expense $55 million of costs no longer eligible for capitalization. Excluding accounting changes, the forecasted increase in 2015/16 of 1.1% is a result of contract wage settlements, which is mainly offset by the Corporation’s cost containment initiatives.

2016/17 Forecast vs. 2015/16 Forecast

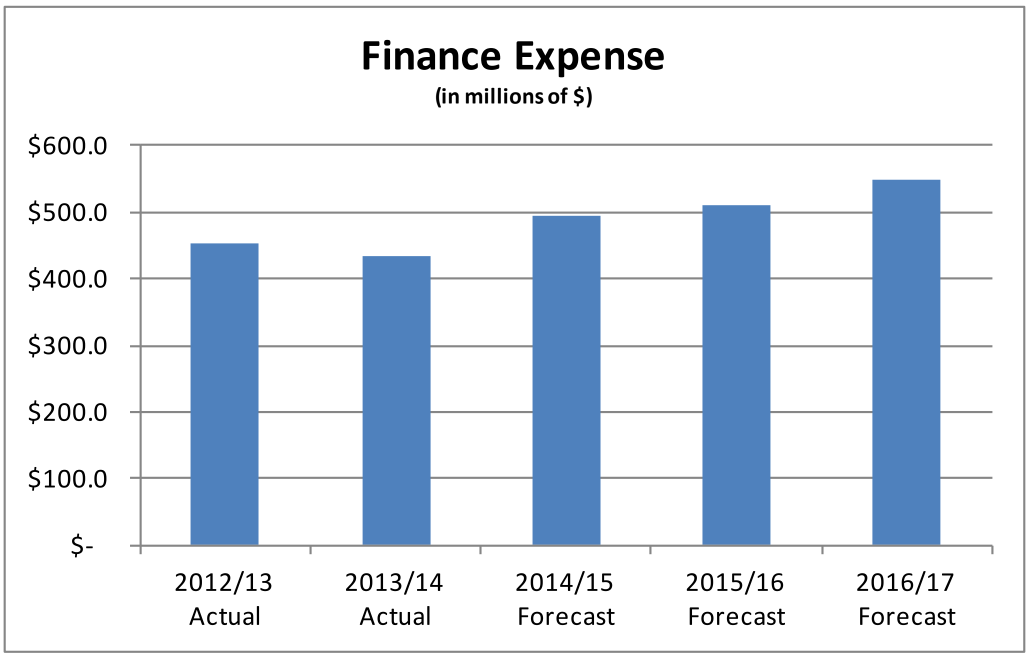
The 2016/17 forecast increase is primarily attributable to higher pension costs due to an increase in interest on the obligation and higher pensionable earnings. Excluding accounting changes, the forecasted increase in 2016/17 of 1.1% is the result of expected escalation in wages and salaries, mainly offset by the Corporation's cost containment initiatives.

Appendix 5.5 provides additional comprehensive information on Equivalent Full Time positions ("EFTs"), OM&A costs by category and Business Unit.

5.6 FINANCE EXPENSE

Finance expense consists of costs associated with the Corporation's financing activities. The largest component of finance expense is gross interest expense on the Corporation's debt portfolio. Finance expense is also affected or partially offset by a number of other components including: the debt guarantee fee; the amortization of discounts, premiums & transaction costs; the income or gains associated with the sinking fund and foreign exchange; and interest capitalized for capital projects under construction.

Figure 5.6 Finance Expense



The following schedule provides for a breakdown of Finance Expense.

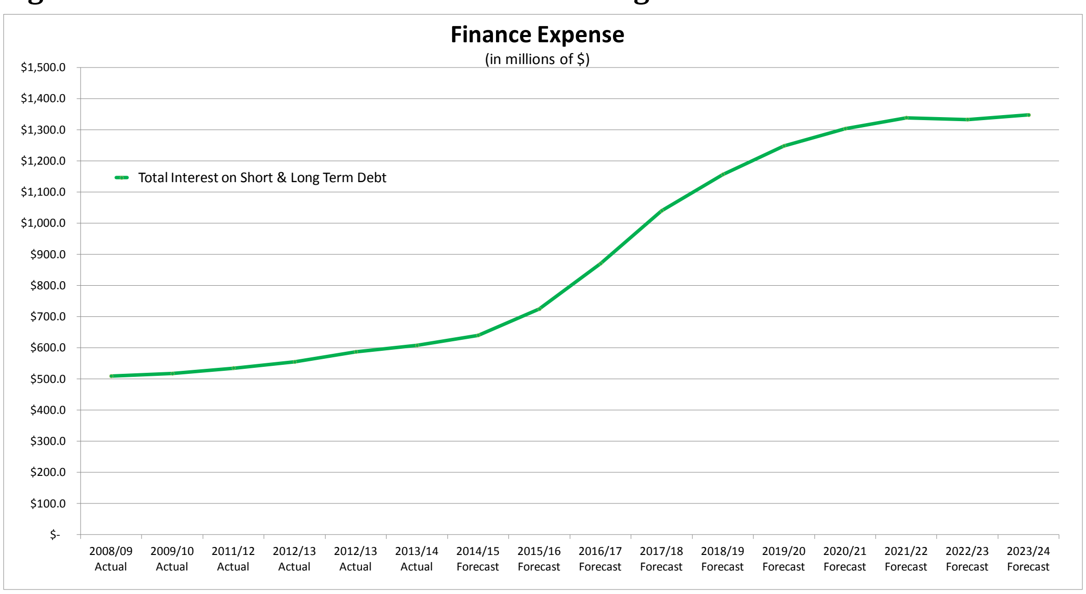
MANITOBA HYDRO
FINANCE EXPENSE

Schedule 5.1.5
(000's)

	2012/13 Actual	**2013/14 Actual**	**2014/15 Forecast**	**2015/16 Forecast**	**2016/17 Forecast**
Interest on Short & Long-Term Debt					
Gross Interest	$ 515,176	$ 528,490	$ 553,625	$ 626,681	$ 755,717
Provincial Guarantee Fee	90,432	96,228	105,079	118,087	139,830
Amortization of (Premiums), Discounts, and Transaction Costs	121	1,752	2,832	2,812	2,212
Intercompany Interest Receivable	(18,544)	(18,671)	(21,089)	(23,059)	(27,185)
Total Interest on Short & Long Term Debt	587,185	607,799	640,447	724,521	870,574
Interest Allocated to Construction	(137,904)	(139,542)	(145,615)	(206,840)	(315,634)
Interest Earned on Sinking Fund	(9,957)	(24,475)	(14)	(2,234)	(8,703)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	2,058	(19,326)	(10,982)	(16,830)	(10,649)
Revaluation of Dual Currency Bonds	2,984	2,372	935	1,028	1,083
Corporate Allocation	(19,129)	(19,129)	(18,685)	(18,543)	(18,543)
Other Amortization	27,128	27,703	28,766	29,321	29,393
Total Finance Expense	$ 452,367	$ 435,402	$ 494,852	$ 510,423	$ 547,521
Year over year $ change		$ (16,965)	$ 59,450	$ 15,571	$ 37,098
Year over year % change		-3.8%	13.7%	3.1%	7.3%

Manitoba Hydro is forecasting that in the next 10 years it will be necessary to fund the vast majority of its capital expenditures through debt financing. When combined with debt refinancing requirements, the total debt requirements for Manitoba Hydro's electric operations in the next five-year period will peak at levels in excess of $3 billion per year. These total forecast debt financing requirements are unprecedented in Manitoba Hydro's history. For finance expense, the total interest on short & long term debt is shown as the green line on the following figure:

Figure 5.7 Total Interest on Short-term & Long-term Debt



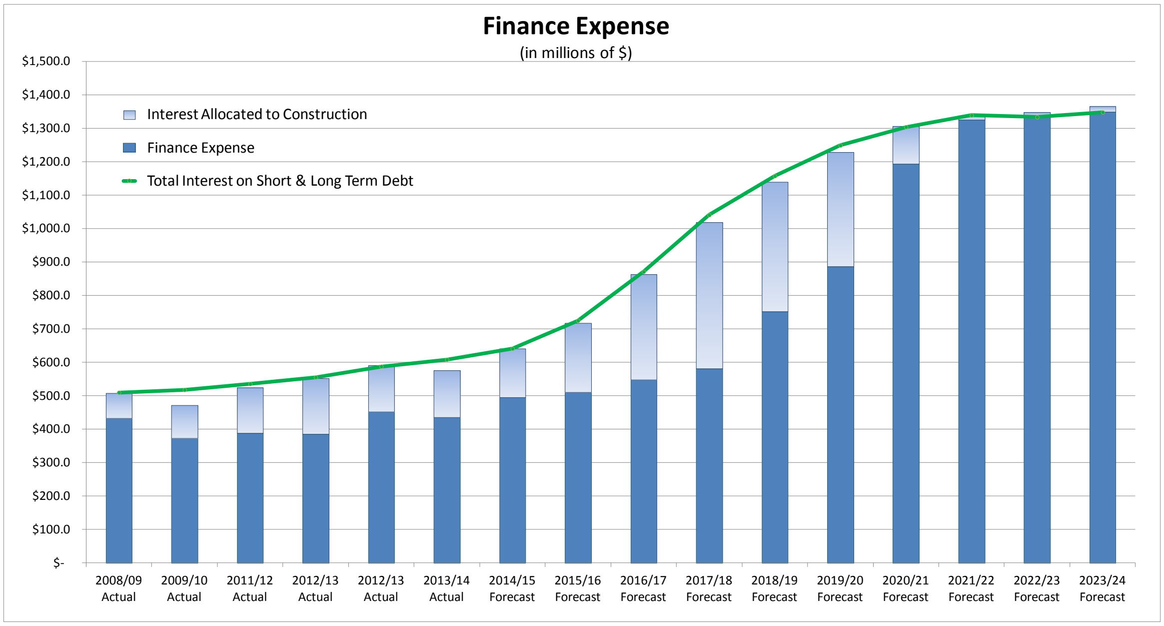
The components within this category are as follows:

- Gross Interest is the interest paid on Canadian and US dollar debt.
- The Provincial Guarantee Fee (PGF) is an annual fee payable to the Province of Manitoba in exchange for the guarantee of the Corporation's debt (with the exception of Manitoba Hydro-Electric Board Bonds) and is calculated using a rate of 1% multiplied by the applicable outstanding debt at March 31st of the previous fiscal year.
- The Amortization of Premiums, Discounts and Transaction Costs, arising from actual debt issuance on the existing debt portfolio are amortized over the term of the debt.
- The Intercompany Interest Receivable is primarily from the interest received from Manitoba Hydro's subsidiary, Centra Gas Manitoba Inc. ("Centra"), on the short and long term debt advances made to Centra from Manitoba Hydro. Interest rates for advances to Centra are based on the associated cost of financing that was incurred by Manitoba Hydro.

The actual and forecasted level of total interest on short & long term debt generally follows the growth in the size of the total debt portfolio financing the expansion of the Corporation's net capital assets. Commencing with 2015/16, the gross interest and PGF levels will begin to rise sharply in accordance with the escalation in capital financing, until 2021/21 when the overall levels flatten as capital investments subside.

The Interest Allocated to Construction is the interest capitalized during the construction of a project, which is a reduction to finance expense and a charge to the capital project. The interest associated with a capital project is not included in finance expense until the project is placed into service. As shown in the following figure, the interest allocated to construction (lightly shaded blue bars) is the primary factor that reduces the level of total interest on short & long term debt (green line) to arrive at net finance expense (dark blue bars) on the financial statements.

Figure 5.8 Finance Expense and Interest Allocated to Construction



Consequently, during periods of intensive capital construction, the net finance expense, and hence the revenue requirement, is temporarily shielded from the full weight of the gross finance expense by the interest allocated to construction. By 2021/22, as the level of capital investments subside, the net finance expense closely approaches the total interest on short and long term debt of over $1.3 billion per year.

In addition to the interest allocated to construction, there are a number of other components within finance expense as follows:

- The Interest Earned on Sinking Fund is primarily the interest recognized on Canadian and US sinking fund investments/ cash.
- The Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges, arising from the difference between the historic and market exchange rates on US dollar debt, are recorded in Finance Expense when hedged export revenues are realized.
- The Revaluation of Dual Currency Bonds is primarily a measure of the quarterly change in present value of the USD interest payments as translated into Canadian currency at the exchange rate prevailing at the balance sheet date.
- The Corporate Allocation amount includes the interest on the Centra acquisition debt and the related Provincial Guarantee Fee. This amount is included in the

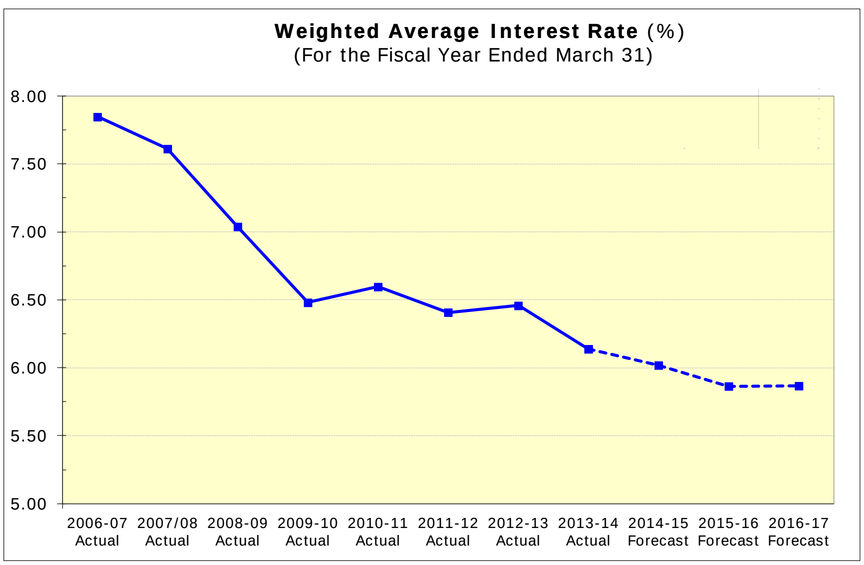
Corporate Allocation in Section 5.11.

- Other Amortization is primarily the amortization of the Winnipeg Hydro obligation and First Nations settlements.

While the forecasted increases in net finance expense primarily arise as capital assets go in-service and net finance expense is no longer reduced by the associated interest allocated to construction, gross interest expense arising from debt obligations will be affected by changing interest rates for new and refinanced debt requirements, as well as the debt portfolio's floating rate debt. Changing interest rates will also have a counterbalancing impact upon the interest capitalization rate used to derive the interest allocated to construction.

The low interest rate environment over the past few years has provided the opportunity for Manitoba Hydro to secure stable, low cost funding such that the weighted average interest rate on the debt portfolio has decreased. As shown on the following figure, since 2006/07, the debt portfolio's net weighted average interest rate has decreased by nearly 2.0%. It is anticipated that this positive trend will continue until leveling off in 2016/17.

Figure 5.9 Weighted Average Interest Rate



Although economic forecasts during the last few years have generally called for a quicker economic recovery and correspondingly higher interest rates, on an actual basis, the strength and pace of a recovery has been subdued. Manitoba Hydro will continue to monitor the financial markets, along with gathering the views of external economic forecasters in order to obtain the range and consensus forecast of their opinions.

The adverse interest rate risk associated with rising interest rates can be minimized through a series of actions such as:

a) reducing the level of variable (or floating) rate debt within the debt portfolio;
b) taking advantage of the historically low interest rate environment for long bonds by securing long term fixed rate financing as required; and
c) enhancing the stability of the debt portfolio by extending the weighted average term to maturity.

See the Debt Management Strategy in Appendix 3.7 for additional information regarding the Corporation's debt financing requirements and strategies.

It is also important to recognize that changes in the interest rate environment arising from macro-economic conditions may affect other aspects of Manitoba Hydro's operations and financial performance. For example, low interest rates may be correlated with low extra-provincial energy prices.

From a liquidity risk perspective, the significant differential between the Corporation's interest cash flow obligations (approximated by the green total interest on short & long term debt) and the accounting net finance expense contribution to revenue requirement (dark blue bars) will place addition pressure upon the Corporation's cash flow and interest coverage ratios.

In order to mitigate the foreign currency exchange risk on export revenues denominated in United States dollars (USD), Manitoba Hydro maintains a natural hedge with USD cash flows, including finance expense cash flows from US denominated debt. For example, to the extent that the underlying USD inflows and outflows are in balance, while a strengthening US dollar will increase the translation of US export revenues into Canadian dollars (CAD), this change will be offset by increases in the translation of US dollar expenses (such as US dollar interest expense) into CAD.

The following sections highlight the year-over-year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The decrease was primarily due to lower interest rates, higher realized foreign exchange gains on U.S. debt and higher recognized gains on the sale of U.S. sinking fund investments. This was partially offset by higher volumes of long term debt to finance capital expenditures and a weaker Canadian dollar.

2014/15 Forecast vs. 2013/14 Actual; 2015/16 Forecast vs. 2014/15 Forecast; and 2016/17 Forecast vs. 2015/16 Forecast

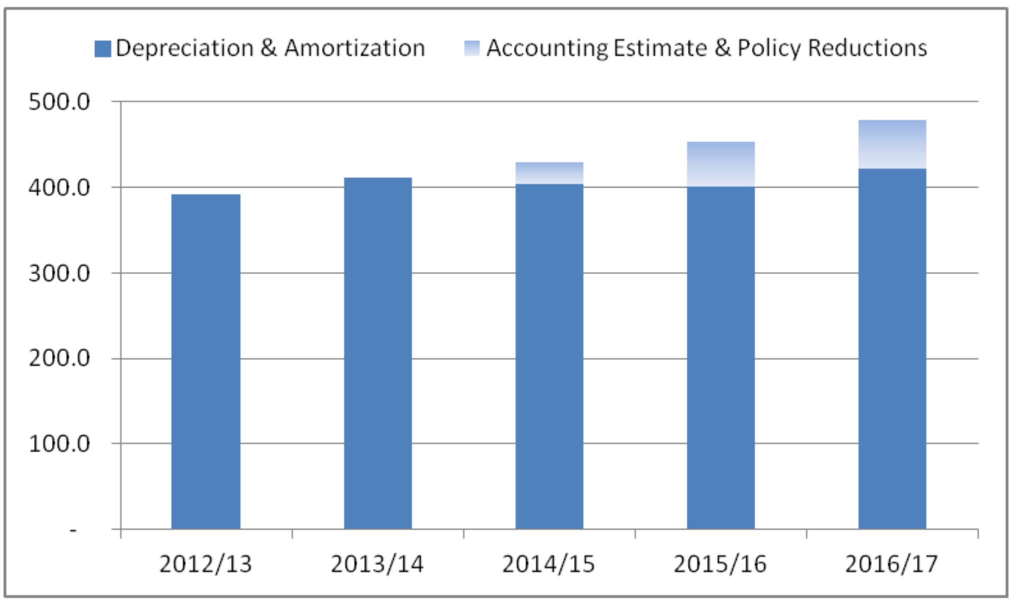
Gross interest expense increases during the forecast years, primarily due to new long term debt issued in finance the Corporation's capital investments as well as interest rates that are projected to rise to more normalized levels by the final forecast year. As a partial offset, any interest associated with funding capital projects under construction is capitalized, thereby reducing total finance expense.

5.7 DEPRECIATION & AMORTIZATION

Depreciation and Amortization expenses are calculated using a straight line remaining life basis. The asset categories include: Generation, Transmission, Distribution, and Other (General Equipment, Communication Equipment, Buildings, and Vehicles). Also included is the amortization of non-refundable customer contributions, regulated assets and intangible assets.

Figure 5.10 below shows the lower depreciation and amortization expense reflecting the change in estimate as a result of adjustments in asset service lives, removal of negative salvage from depreciation rates and the impact of the change in depreciation methodology.

Figure 5.10 Depreciation & Amortization



Please see the following schedule for a breakdown of Depreciation and Amortization.

MANITOBA HYDRO — **Schedule 5.1.6**
DEPRECIATION AND AMORTIZATION EXPENSE — **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Generation					
Hydraulic Generating Stations	80 110	82 678	92 953	92 265	96 041
Thermal Generating Stations	15 415	15 562	15 770	15 755	15 856
Demand Side Management	28 217	30 262	31 576	34 957	37 501
Diesel Generating Stations	1 457	1 757	2 342	2 557	2 111
Wuskwatim	16 179	26 688	26 651	26 984	27 082
Amortization of Contributions	(841)	(868)	(1 049)	(1 146)	(1 146)
	$ 140 537	$ 156 079	$ 168 244	$ 171 373	$ 177 446
Transmission					
Transmission	14 571	16 644	15 929	13 369	14 367
Amortization of Contributions	(1 358)	(3 204)	(3 051)	(3 054)	(3 059)
	$ 13 213	$ 13 440	$ 12 879	$ 10 315	$ 11 308
Stations					
Substations	82 493	86 122	87 617	85 735	90 177
Transformers	1 806	1 940	1 627	1 597	1 828
Amortization of Contributions	(1 247)	(4 457)	(4 402)	(4 402)	(4 402)
	$ 83 052	$ 83 605	$ 84 842	$ 82 930	$ 87 603
Distribution					
Subtransmission Lines	6 271	6 629	7 376	6 948	7 401
Distribution Lines	58 170	61 337	60 509	56 989	60 951
Meters & Transformers	4 273	4 260	2 848	3 281	3 404
Amortization of Contributions	(5 084)	(5 476)	(5 699)	(6 409)	(7 009)
	$ 63 630	$ 66 750	$ 65 034	$ 60 809	$ 64 747
Other					
Communications	19 192	21 307	16 819	17 765	18 206
Motor Vehicles	10 954	11 573	10 154	11 819	12 226
Structures & Improvements	7 947	8 066	7 928	8 800	9 557
General Equipment	25 806	23 255	16 627	16 780	16 797
Computer Development	20 582	19 667	17 687	18 487	20 816
Conawapa	-	-	-	-	7 711
Affordable Energy Fund	5 406	4 410	5 270	4 290	1 509
Miscellaneous	3 550	4 628	1 701	2 652	3 269
Corporate Allocation	(1 946)	(1 946)	(1 974)	(1 850)	(1 853)
Target Adjustment	-	-	(621)	(3 305)	(6 938)
	$ 91 491	$ 90 960	$ 73 591	$ 75 439	$ 81 300
Total D&A Expense Including Accounting Changes	$ 391 923	$ 410 834	$ 404 590	$ 400 866	$ 422 404
Add: Accounting Policy & Estimate Changes	-	-	**24 923**	**52 685**	**57 159**
Total D&A Expense Excluding Accounting Changes	$ 391 923	$ 410 834	$ 429 512	$ 453 551	$ 479 563
Year over year % change Including Accounting Changes		4.8%	-1.5%	-0.9%	5.4%
Year over year % change Excluding Accounting Changes		**4.8%**	**4.5%**	**5.6%**	**5.7%**

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is primarily due to new additions to plant and equipment coming into service, including the Wuskwatim Generating Station which was fully in-service during the 2013/14 fiscal year.

2014/15 Forecast vs. 2013/14 Actual

Fiscal 2014/15 reflects an increase in depreciation expense as a result of $1.7 billion in assets going into service. Of the $1.7 billion in additions, approximately $1.0 billion is comprised of new generation and transmission projects including the Pointe du Bois Spillway Replacement ($477 million), the Riel 230/500 KV Station ($329 million), and Bipole III Converter Station ($123 million), with $576 million comprised of sustaining capital investments.

The increase in depreciation expense as a result of plant additions is more than offset by the impact of new depreciation rates implemented by Manitoba Hydro. The new depreciation rates were determined as part of Manitoba Hydro's most recent depreciation study and reflect new service life estimates effective April 1, 2014.

Please see Appendix 5.6 for a discussion of the depreciation study and the associated depreciation rates and for correspondence from Gannett Fleming, Inc. setting out the depreciation rates to be used under GAAP and IFRS.

2015/16 Forecast vs. 2014/15 Forecast

Similar to the results reflected in the 2014/15 forecast, depreciation continues to increase as result of $833 million in plant assets going into service in the 2015/16 fiscal period. The majority of the assets forecast to go into service are comprised of sustaining capital investments of $593 million.

Overall depreciation decreases as a result of changes implemented by Manitoba Hydro in order to comply with the financial reporting requirements of IFRS. These changes include the removal of the provision for asset retirement costs from depreciation rates, the removal of administrative overhead from inclusion in the cost of capital projects, and the change in method of depreciation. The removal of the provision for asset retirement costs and the removal of administrative overhead from the cost of capital projects resulted in a decrease in depreciation expense totaling $60 million that was partially offset by a $36 million increase caused by the change in method of depreciation.

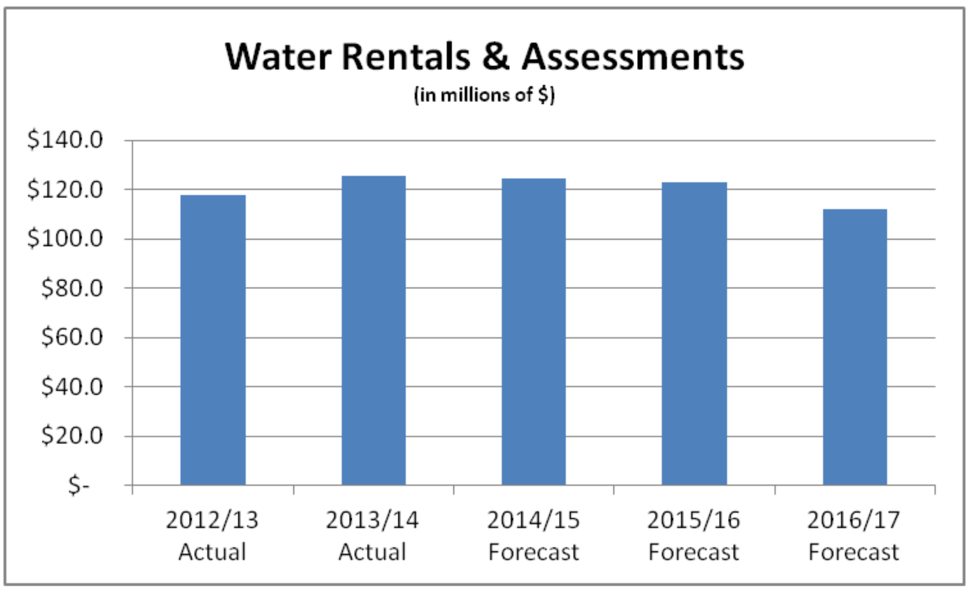
2016/17 Forecast vs. 2015/16 Forecast

The $21 million increase forecasted in 2016/17 is the result of $0.9 billion of assets going into service in fiscal 2016/17 (comprised of $692 million in sustaining capital investments), as well as the projected commencement of the amortization of deferred Conawapa project costs. For purposes of MH14, it is assumed that the deferred Conawapa costs are treated as a rate-regulated asset beginning in 2016/17.

5.8 WATER RENTALS & ASSESSMENTS

Pursuant to *The Water Power Act*, water rentals are paid to the Province for the use of water resources for hydroelectric generation. Assessments include amounts paid for water usage pursuant to *The Water Rights Act*, Lake of the Woods Control Board and Lac Seul Operating Costs, National Energy Board (NEB) assessments, and membership fees for MISO and other industry associations. Land rentals are annual payments for the use of Manitoba Crown lands used for water power purposes, as set out in Manitoba Hydro's Water Power Act licenses.

Figure 5.11 Water Rentals & Assessments



Please see the following schedule for a breakdown of Water Rentals and Assessments.

MANITOBA HYDRO **Schedule 5.1.7**
WATER RENTALS AND ASSESSMENTS **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Water Rentals	$ 110 440	$ 117 907	$ 117 417	$ 115 049	$ 103 902
Assessments & Land Rentals	7 424	7 610	7 052	7 798	8 265
Total Water Rentals and Assessments	$ 117 864	$ 125 517	$ 124 469	$ 122 847	$ 112 167
Year over year $ change		$ 7 653	$ (1 047)	$ (1 622)	$ (10 680)
Year over year % change		6.5%	-0.8%	-1.3%	-8.7%

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is primarily due to increased water rentals due to an increase in hydraulic generation along the Nelson River as a result of higher system inflows compared to 2012/13. Also, the Wuskwatim Generating Station was in service for the entire year which contributed to the increase in the total water rental cost for 2013/14.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast decrease reflects lower hydraulic generation largely due to transmission outages that restricted exports on the US transmission line during October and November 2014.

2015/16 Forecast vs. 2014/15 Forecast

The 2015/16 forecast decrease reflects lower hydraulic generation due to assumed median inflow conditions as compared to above average inflow conditions that occurred in 2014/15. Although lower than 2014/15, hydraulic generation is still expected to be above average due to significant carry over storage from 2014/15. The decrease in water rentals is expected to be partially offset by higher membership fees and assessments due to an increase in NEB charges.

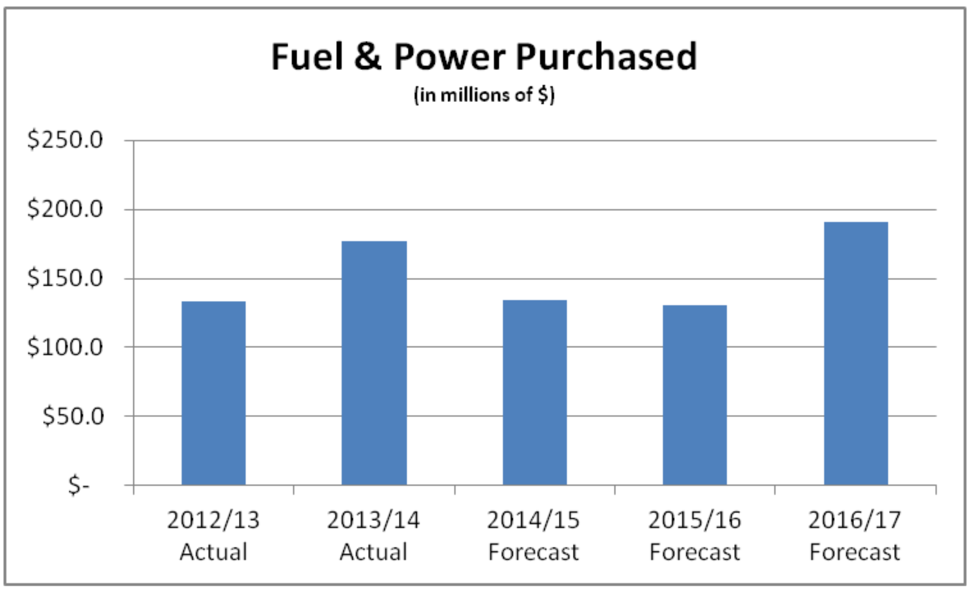
2016/17 Forecast vs. 2015/16 Forecast

The 2016/17 forecast decrease reflects lower water rentals due to lower hydraulic generation based on the assumption of average historic water flow conditions. Hydraulic generation, and therefore water rentals, is expected to be higher in 2015/16 primarily because of carry forward storage from the prior year.

5.9 FUEL & POWER PURCHASED

Fuel & Power Purchased includes costs of fuel for thermal generation facilities, costs for purchased energy, and other miscellaneous costs associated with export and import market activities and system operation. In 2014/15, over 99% of electricity forecast to be generated by Manitoba Hydro is from its 15 hydraulic generating stations and less than 1% from its two thermal generation stations and four remote diesel generation facilities. In addition, Manitoba Hydro purchases wind power from the independently-owned St. Leon and St. Joseph wind farms. Manitoba Hydro also imports electricity depending on the operating and economic circumstances.

Figure 5.12 Fuel & Power Purchased



Please see the following schedule for a breakdown of Fuel & Power Purchased.

MANITOBA HYDRO **Schedule 5.1.8**
FUEL AND POWER PURCHASED **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Thermal Fuel					
Coal	$ 3 305	$ 4 886	$ 3 566	$ 3 086	$ 6 329
Natural Gas & Other	9 012	9 183	9 262	10 574	21 542
Power Purchased	70 965	98 104	70 996	73 651	115 049
Merchant Purchases	5 366	18 863	7 407	5 705	-
Transmission Charges	44 644	46 078	42 958	37 416	48 013
Total Fuel and Power Purchased	$ 133 292	$ 177 113	$ 134 189	$ 130 432	$ 190 933
Year over year $ change		$ 43 821	$ (42 925)	$ (3 757)	$ 60 501
Year over year % change		32.9%	-24.2%	-2.8%	46.4%

Please see the following for a description of Fuel & Power Purchased components:

Coal purchases refers to the charge for coal consumed as the principal fuel for Brandon Unit 5 for the purpose of generating electricity under restricted operations.

Natural Gas & Other includes natural gas, oil and diesel requirements for Brandon and Selkirk, and diesel for remote locations for the purpose of generating electricity.

Power Purchased includes purchases of electrical energy from wind farms in Manitoba as well as from external Canadian and US suppliers.

Merchant purchases represent arbitrage opportunities and are unrelated to Manitoba Hydro generation. These include physical purchases of power from one market for re-sale to another market.

Transmission Charges relate primarily to reservation fees for use of transmission facilities for imports or exports, or for merchant transactions.

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase was primarily the result of higher purchased volumes due to colder weather during the winter of 2013/14. Merchant purchases were also higher in 2013/14 due to increased arbitrage opportunities between markets.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast decrease is primarily the result of lower purchased volumes due to the assumption of normal weather and a year-over-year projected increase in hydraulic generation during the winter period. Merchant purchases are also projected to be lower in 2014/15 as Manitoba Hydro does not expect to have the same level of arbitrage opportunities between markets as was experienced in 2013/14. Transmission charges are also projected to be lower largely because of 100 MW of transmission service expiring in the third quarter of 2014/15.

2015/16 Forecast vs. 2014/15 Forecast

The 2015/16 forecast decrease is the result of reduced merchant purchases due to less arbitrage opportunities forecast for 2015/16. Transmission charges are also reduced because of a 100 MW transmission service that expired towards the end of 2014/15, with the effect being fully realized in 2015/16. These reductions are partially offset by an increase in off-peak imports as a consequence of reduced hydraulic generation.

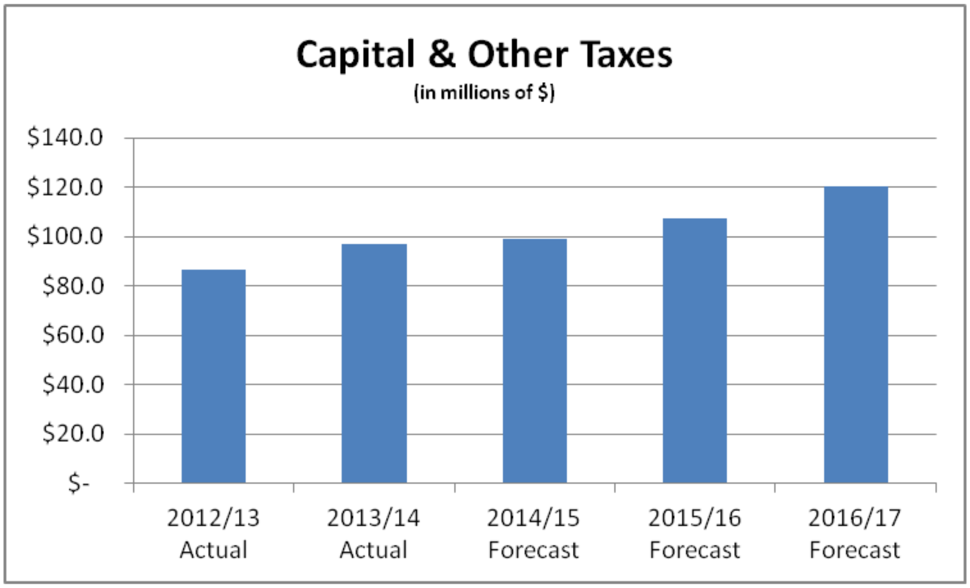
2016/17 Forecast vs. 2015/16 Forecast

The 2016/17 forecast increase is primarily due to increases in the volumes of US off-peak purchases and increased thermal costs. These increases are largely because the 2016/17 forecast reflects average purchases and costs based on the full range of historic flows with consideration for drought included, whereas 2015/16 is based on hydraulic generation from median inflows coupled with above average carry forward storage from 2014/15. Transmission charges are projected to increase due to 200 MW of new transmission service as of November 1, 2016.

5.10 CAPITAL & OTHER TAXES

Capital and Other Taxes is comprised of payments made to the Province of Manitoba for capital and payroll taxes as well as grants in lieu of taxes (“grants in lieu”), and business and property taxes paid to the various municipalities in Manitoba.

Figure 5.13 Capital & Other Taxes



The following schedule provides a breakdown of Capital and Other Taxes.

MANITOBA HYDRO | **Schedule 5.1.9**
CAPITAL AND OTHER TAXES | **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Capital Tax	$ 54 948	$ 59 780	$ 63 605	$ 70 408	$ 82 726
Grants in Lieu of Taxes	13 115	13 851	14 383	14 807	15 245
Payroll Tax	10 767	11 039	11 517	11 933	12 172
Business & Property Tax	1 174	1 152	1 165	1 168	1 197
Other Municipal Payments	6 395	7 612	8 500	8 840	9 194
GST Reassessment on City Tax	-	3 316	-	-	-
Total Capital & Other Taxes	$ 86 399	$ 96 750	$ 99 170	$ 107 156	$ 120 534
Year over year $ change		$ 10 351	$ 2 420	$ 7 986	$ 13 378
Year over year % change		12.0%	2.5%	8.1%	12.5%

The following provides a description of Capital & Other Tax components:

The Corporation pays capital tax to the Province of Manitoba at a rate of 0.5% and is applied to the taxable capital of the company.

The Corporation pays grants in lieu on its land and buildings. The amount of grants in lieu paid is determined based on property valuations and municipal and school division mill rates, similar to the manner in which property taxes are determined for other tax payers in Manitoba.

Payroll tax is based on a tax rate of 2.15% which is applied to the Corporation's gross payroll. A portion of the payroll taxes paid is allocated to Centra based on the relative percentage of activity charges to gas programs.

Business taxes are paid with respect to commercial space occupied by the company in both leased and owned properties. The Corporation pays property taxes to the landlords of leased premises as part of the required lease payments.

The Corporation also makes other municipal payments with respect to the town of Gillam and the Frontier School Division.

The Canada Revenue Agency ("CRA") performed an audit with respect to an issue regarding GST being charged to customers. It was determined that the GST should be applied to the City of Winnipeg tax charged to customers. In 2013/14 the Corporation was assessed, and accrued for, past taxes not collected from customers in the amount of $3.3 million.

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is higher than expected partially due to the inclusion of the $3.3 million Canada Revenue Agency GST audit reassessment. The remainder of the increase is largely driven by the increase in provincial capital tax which is linked to increasing debt levels to fund capital investments. Other municipal payments have also increased at a rate higher than inflation due to increased funding requirements relating to the town of Gillam.

2014/15 Forecast vs. 2013/14 Actual

The forecast 2014/15 increase is primarily due to higher capital taxes. Going forward, all years will be impacted by capital taxes increasing at greater than the rate of inflation due to higher capital investment increasing debt levels. Other municipal payments relating to the town of Gillam also continue to increase due to operational funding needs.

2015/16 Forecast vs. 2014/15 Forecast

Capital tax is higher due to increased capital spending for Keeyask, Bipole III and aging infrastructure. All other items are forecast to generally increase in line with inflation.

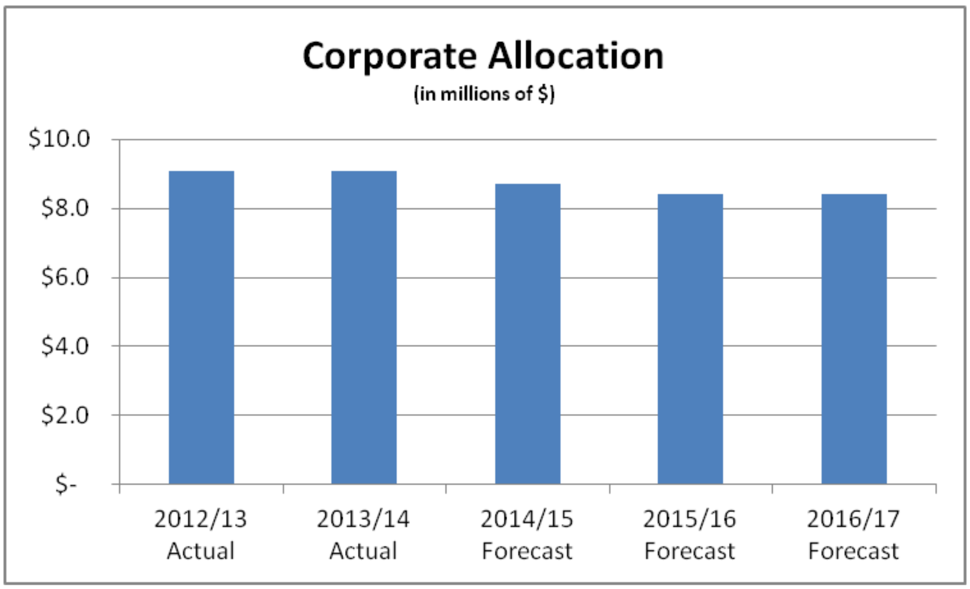
2016/17 Forecast vs. 2015/16 Forecast

Capital tax is higher due to increased capital spending for Keeyask, Bipole III and aging infrastructure. All other items are forecast to generally increase in line with inflation.

5.11 CORPORATE ALLOCATION

Corporate Allocation includes Manitoba Hydro Electric operations' share of the acquisition costs relating to Centra. The total annual acquisition cost of Centra includes the interest and provincial guarantee fee ("PGF") on the acquisition debt, and the amortization of the acquisition and integration costs. The total ranges from $20 to $21 million annually. Of this amount, $12 million is charged to the natural gas operations. The remainder is charged to Electric operations.

Figure 5.14 Corporate Allocation



Please see the following schedule for a breakdown of Corporate Allocation.

MANITOBA HYDRO **5.1.10**
CORPORATE ALLOCATION **(000's)**

		2012/13 Actual		2013/14 Actual		2014/15 Forecast		2015/16 Forecast		2016/17 Forecast
Corporate Allocation Electric										
Interest on Acquisition Debt	$	16 628	$	16 628	$	16 185	$	16 043	$	16 043
Provincial Guarantee Fee on Acquisition Debt		2 500		2 500		2 500		2 500		2 500
Finance Expense Corporate Allocation		19 128		19 128		18 685		18 543		18 543
Corporate Allocation - Depreciation		1 946		1 946		1 974		1 850		1 853
		21 074		21 074		20 659		20 393		20 396
Less: Allocation to Centra Gas		(12 000)		(12 000)		(12 000)		(12 000)		(12 000)
Total Corporate Allocation (Electric)	$	9 074	$	9 074	$	8 659	$	8 393	$	8 396
Year over year $ change			$	-	$	(415)	$	(266)	$	3
Year over year % change				0.0%		-4.6%		-3.1%		0.0%

The following sections highlight the year over year changes from 2012/13 through 2016/17.

2013/14 Actual vs. 2012/13 Actual

No significant change.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast decrease is primarily due to lower interest rates from refinancing the Centra acquisition debt.

2014/15 Forecast vs. 2015/16 Forecast

The 2015/16 forecast decrease is primarily due to a full year of lower interest rates from the previous year's refinancing.

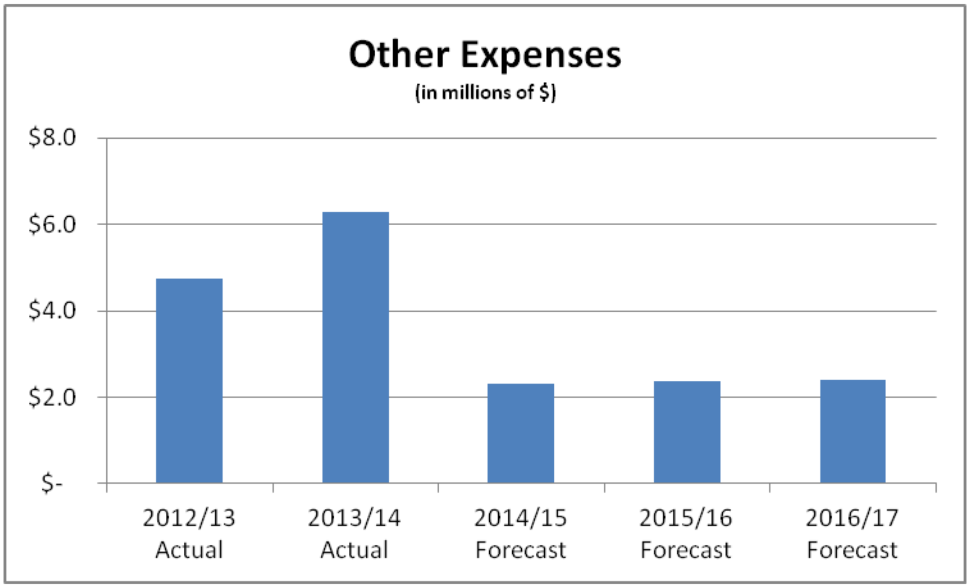
2016/17 Forecast vs. 2015/16 Forecast

No significant change.

5.12 OTHER EXPENSES

Other expenses include costs associated with the provision of work on customer owned plant and other miscellaneous expenditures.

Figure 5.15 Other Expenses



MANITOBA HYDRO | **Schedule 5.1.11**
OTHER EXPENSES | **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Other Expenses	$ 4 750	$ 6 294	$ 2 311	$ 2 355	$ 2 402
$ Change		$ 1 544	$ (3 983)	$ 44	$ 47
% Change		32.5%	-63.3%	1.9%	2.0%

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase is the primarily the result of a one-time write off of property, plant and equipment under construction.

2014/15 Forecast vs. 2013/14 Actual

The decrease in expenses results from the one-time write-off in 2013/14.

2015/16 Forecast vs. 2014/15 Forecast

No significant change.

2016/17 Forecast vs. 2015/16 Forecast

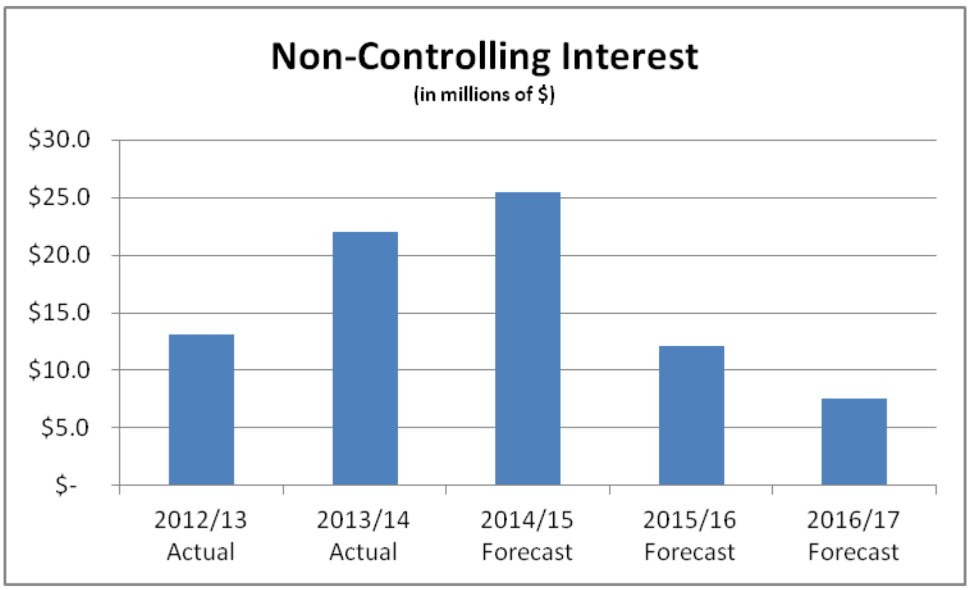
No significant change.

5.13 NON-CONTROLLING INTEREST

The Wuskwatim Power Limited Partnership ("WPLP") has two limited partners, Manitoba Hydro and Taskinigahp Power Corporation ("TPC") which is beneficially owned by Nisichawayasihk Cree Nation ("NCN") and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro. NCN may acquire up to a 33% interest in WPLP. The generating station and associated transmission was placed into service during the 2012/13 year. Manitoba Hydro will operate and maintain the Wuskwatim generating station and purchase all of the output under the power purchase agreement with WPLP.

Manitoba Hydro's income statement includes all of the WPLP revenues and expenses. TPC's 33% portion of the operating results of the WPLP is recorded as non-controlling interest in the consolidated statement of income.

Figure 5.16 Non-Controlling Interest



MANITOBA HYDRO | **Schedule 5.1.12**
NON-CONTROLLING INTEREST | **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Non-controlling Interest	$ 13 160	$ 22 005	$ 25 452	$ 12 126	$ 7 580
$ Change		$ 8 845	$ 3 447	$ (13 326)	$ (4 546)
% Change		67.2%	15.7%	-52.4%	-37.5%

The following sections highlight the year over year changes from 2012/13 through 2016/17:

2013/14 Actual vs. 2012/13 Actual

The 2013/14 increase reflects the first full year of operations for the WPLP as the first of three units at the Wuskwatim generating station entered commercial service in June 2012.

2014/15 Forecast vs. 2013/14 Actual

The 2014/15 forecast increase results from the projection of lower revenues due to reduced forecast volumes and lower projected export prices and higher finance expense than recorded in 2013/14.

2015/16 Forecast vs. 2014/15 Forecast & 2016/17 Forecast vs. 2015/16 Forecast

Manitoba Hydro and NCN have reached an agreement in principle with respect to the majority of terms within the Wuskwatim Project Development Agreement (PDA). The parties are still reviewing and negotiating the final terms of the PDA. The draft terms contained in the PDA related to the power purchase agreement between Manitoba Hydro and the WPLP improve the financial results of the partnership and as a result, reduce the loss that is allocated to TCP through non-controlling interest.

5.14 COST SAVING INTIATIVES

Manitoba Hydro continues to undertake a number of initiatives that are intended to result in both operating and capital cost savings, ultimately improving financial results and easing pressures on rates. These initiatives support the Corporation's commitment to manage its OM&A expenditures below inflationary levels and support Manitoba Hydro's debt management strategy by reducing capital investment resulting in lower overall debt & depreciation requirements.

OM&A cost increases have been limited to 1% per year up to 2021/22 (excluding accounting changes and the increases associated with new major generation and transmission projects coming into service). After 2021/22, OM&A is projected to rise at the same level as inflation, despite the increasing cost pressures facing the Corporation from investments required for infrastructure renewal and increased capacity.

The following describes some of the key ongoing initiatives being undertaken by the corporation to manage its overall operating and capital expenditures.

5.14.1 Reduction of Operational Positions

Over the forecast period (2014/15 through 2016/17), Manitoba Hydro has committed to a reduction of approximately 300 operational positions and a commitment to hold non-labor costs below inflation, where possible. Manitoba Hydro intends to leverage its current attrition rate of approximately 300 staff per year by analyzing work processes and functions to identify opportunities for elimination, consolidation or technology enhancements that will result in staff reductions and efficiencies while still maintaining service levels. The reductions will vary across the corporation and are dependent upon the review of the many varied processes and functions unique to each area.

5.14.2 Consolidation of Rural District Offices

This initiative entails the closure of 24 rural district offices and their consolidation into the existing 20 Customer Service Centres. This effort is expected to enhance customer service through improved field crew deployment from the recently implemented Mobile Workforce Management System, improve system reliability by increasing distribution maintenance efforts and economize on customer-based administrative tasks.

Consolidation of the rural district offices is expected to yield a reduction in operating costs of approximately $2 million per year and result in the avoidance of future facility upgrade expenditures of $50 million and potential sales revenue of vacated properties. The first stage of facilities closures began in January 2014. The timing of this initiative is a result of declining district office traffic, increased customer demand for on-line services and increased customer requests at the previously established customer service centre hubs. This initiative is expected to maintain or improve outage response times.

Opportunities are also being derived in the centralizing of administrative work processes at Customer Service Centres. Amalgamating district staff into the larger Customer Service Centres has enabled Manitoba Hydro to create a more specialized and flexible workforce that is better equipped to respond to service disruptions. The Corporation also continues to monitor service levels and explore opportunities to optimize customer service, particularly in the areas of self-service and web-based outage information.

5.14.3 Managing Contractor Costs in Various Projects

The management of costs for capital projects involves proactively managing the schedule, scope and risks to the project. Manitoba Hydro has put in place industry standard project controls such as frequent schedule and cost monitoring with a focus on understanding the past and current costs. Manitoba Hydro is implementing a number of strategies throughout the lifecycle of major projects such as Bipole III and Keeyask.

For the procurement process, Manitoba Hydro has generally been following a multi-stage process where proponents are initially prequalified on their ability to complete the construction work, with pre-qualified proponents then competing largely on price to maximize competitiveness of the process and determine the successful proponent. In some instances, the work is awarded as a fixed price and pre-qualified proponents have input into finalization of contractual terms during the proposal phase, which balances risk between Manitoba Hydro and the proponents and reduces the overall uncertainty in the bids. The result was that proponents were able to reduce the amount of risk dollars carried in their bids, reducing overall bid price. In some instances, Manitoba Hydro informed all proponents that commercial and technical alternatives that may offer cost savings while still meeting the requirements of the contract would be considered resulting in noticeable cost savings.

5.14.4 Review of the Gillam Redevelopment and Expansion Project (GREP)

Manitoba Hydro undertook a review of the Gillam Redevelopment and Expansion Project (GREP) which involved assessing changing business requirements and developing a strategy that reflected these changes while applying the most current northern community design practices.

The revised community development plan incorporated a number of modifications including: eliminating expansion of infrastructure while strengthening community through enhanced centralized amenities, eliminating further expansion of new retail/commercial space, cancelling construction of a new 75 single detached unit housing subdivision substantially reducing the number of additional residential sub-divisions and new housing units, limiting/eliminating expansion of the existing trailer court sub-division, and cancelling construction of a new Wellness Centre.

In place of these developments, Manitoba Hydro's current plan is to expand mid-density housing within existing infrastructure, and upgrade and enhance recreation and leisure facilities in the Town Centre. The result of this assessment and strategy is a community plan with amenities intended to attract and retain Manitoba Hydro staff in Gillam and a cost savings of approximately $100 million.

5.14.5 Pointe du Bois Operations Spillway Cost Efficiencies

The Pointe du Bois Spillway Project was initiated to update the original spillway in order to meet current dam safety guidelines. The new spillway was placed into service in August 2014. River control has been a continuous challenge for Pointe du Bois Operations over the years due to constant river fluctuation.

The requirement to melt ice off the gates was a manual and very labour intensive process, requiring a crew of almost nine staff to operate the boilers. In addition, the original spillway was not designed to handle the pressure of shifting or expanding ice, and term employees were required to monitor ice thickness and cut trenches in front of the spillway structure.

As a result of the spillway replacement, Manitoba Hydro will see a reduction in OM&A costs. The in-service of the new spillway will result in an immediate and permanent reduction of approximately 1 EFT. In addition, the requirement for utility staff to be on call at all times has been eliminated with the ability to remotely control the river. Finally, the new spillway eliminates the need for boiler operation for melting ice and as a result the 9 positions held by Power Engineers have been deemed redundant.

It is estimated the Pointe du Bois spillway replacement will result in approximately $1 million in cost savings. In addition, the Pointe du Bois spillway structure replacement has resulted in a safer working environment for employees, through the ability to remote control operation.

5.14.6 Implementation of Mobile Workforce Management

Manitoba Hydro has implemented a new mobile workforce management system to effectively manage field activities for both the electric and natural gas businesses. This technology permits the planning, scheduling and dispatching of work orders in an optimized manner to derive cost efficiencies and timely service to customers. Rather than organizing work using geographic specific paper systems, field labour crews are now managed through a scheduling/dispatch centre with the ability to deploy field crews to emergency and urgent customer requests at the same time as improving the throughput of pre-scheduled maintenance work.

Work assignments are now sent to field laptop units electronically where activity details are entered in real time as the work progresses. Customer information and maintenance history are also readily available to field crews and electronic drawings can be retrieved within the vehicle. These field units are also equipped with GPS systems to identify the work locations of all crews.

The benefits of this initiative to customers include an improved ability to schedule appointments with shorter wait times and in precise time slots, improved timeliness of work flow, and the ability to track work orders. The system is also intended to result in faster response times in the event of emergencies. The implementation of mobile workforce management continues to permit the reduction of positions. To date 16 administrative positions have been eliminated and approximately four more positions each year for the next two years are identified for reduction. Field crew productivity savings are also expected due to reduced travel time and standardized matching of skills to job tasks, as well as the ability to complete greater volumes of maintenance work without increasing internal staffing requirements.

Adherence to stringent maintenance schedules is one way to prolong the life of Manitoba Hydro's aging and deteriorating distribution assets. Mobile workforce management has allowed Manitoba Hydro to meet its prescribed facility maintenance requirements, which in turn has helped to modestly relieve some pressure on advancing capital funding to replace distribution assets and also maintain existing levels of electric service reliability.

5.14.7 Asset Management Strategies

Manitoba Hydro is facing cost pressures associated with an aging electric infrastructure. In an ongoing effort to reduce expenditures, the Corporation has been undertaking a number of strategies to reduce overall costs on the electric system equipment while properly managing risk. The following initiatives have been implemented to continually improve the Corporation's asset management strategies.

Further optimization of maintenance programs based on equipment condition, performance and reliability assessments has been completed. A more detailed understanding of the overall condition of major system equipment groups has allowed Manitoba Hydro to strategically increase maintenance intervals on some equipment in relatively good condition. Manitoba Hydro will continue to monitor the overall condition of its major system equipment to ensure that the correct balance between maintenance and equipment replacement costs and reliability is achieved.

Enhanced condition assessments and economic analysis have been implemented to better determine the economic end of life of equipment or equipment groups. This strategy is expected to reduce life cycle costs as well as reduce overall system maintenance costs by undertaking equipment replacements at the optimum time considering cost and risk. A number of programs have been established for some asset types to fund replacements where condition assessments and economic analysis justify proactive replacements.

Various software systems that support asset management processes have been enhanced or replaced with more effective solutions. For example, the Corporation is presently implementing an integrated Enterprise Asset Management system that supports asset management processes at the corporate level, starting initially with the generation, HVDC, protection and communication assets. These types of systems will assist in minimizing equipment failures and also avoid decreases in system availability by ensuring all work is completed in an optimal fashion, and information is recorded to support asset management analysis processes. The Corporation has also implemented reporting enhancements for operating performance and equipment condition analysis, which further strengthens the capital planning process.

5.14.8 Technology Modernization Initiative for Better Capital Investment Decisions

Manitoba Hydro has been working with an external party to evaluate how it can advance its business activities through the use of smarter grid technologies. It is believed that investing today in smarter distribution equipment and information technology will provide economic benefit through enhanced capital improvements to Manitoba Hydro's distribution network over the decades to come.

The expected outcome of this detailed investigative partnership is that the Corporation will be in a far better position to maintain or improve system reliability, manage localized capacity constraints, operate more safely and efficiently, enhance customer service and better manage utility infrastructure with evolving customer load expectations. Other benefits that can be expected include a reduction in field operating costs when responding to outages and enhanced customer knowledge toward greater demand-side management efficiencies.

This investment in technology would allow the Corporation to gain a greater understanding of where capacity constraints and reliability issues specifically reside and prioritize its capital investments in areas that are both critically important and urgent.

5.14.9 Supply Change Management Initiatives

The Corporation is undertaking a number of supply change management initiatives intended to realize savings on goods and services purchased, reduce or avoid operating costs, reduce working capital, reduce capital expenditures on vehicle acquisitions, and reduce costs associated with fuel expenditures and external repairs and maintenance. A number of these initiatives started in 2014/15, while some are scheduled to begin in 2015/16 and 2016/17.

The supply chain management initiatives include implementing stronger category management (procurement) practices; improving inventory management processes; optimizing material distribution networks; improving governance for critical spares inventory; improving forecasting and planning for inventory management; optimizing Manitoba Hydro's vehicle fleet; and, improving the repair, maintenance and fuel supply network for fleet vehicles.

5.14.10 Records Centre Transition to Iron Mountain

Manitoba Hydro is contracting out to a third party service provider the processing and storing of the Corporation's physical records, which is currently managed by the Internal Records Centre. This initiative will deliver cost savings and improve service levels. A third party provider is able to provide a more secure environment for the Corporation's physical records.

As a result of the transition of the Records Centre to a third party provider, there will be a reduction of two EFTs, who are being redeployed to other areas of the Corporation to fill existing vacancies. In addition, this initiative will result in the availability of over 4,600 ft^2 of space to relocate work groups currently located outside of 820 Taylor Avenue. Moreover, service levels will improve with accessibility to physical records 24/7 rather than during Manitoba Hydro regular business hours.

5.14.11 Outage Management System

The implementation of Manitoba Hydro's outage management system is considered one of many steps toward modernizing the Corporation's distribution grid. Manitoba Hydro is continually undertaking efforts and implementing changes in its operations in order to leverage technology and continue to provide reliable customer service with improved labour productivity.

One of these initiatives includes the replacement of Manitoba Hydro's trouble call response system with an Outage Management System. The new system will improve Manitoba Hydro's ability to respond to and restore unplanned outages.

These cost containment measures have assisted the Corporation in maintaining projected annual rate increases at 3.95%, despite the Corporation facing significant and increasing cost pressures. This is consistent with the expectations of the PUB in Order 43/13, wherein it recommended that Manitoba Hydro control OM&A costs increases below inflation.

Re-powering our province

Manitoba Hydro-Electric Board
63rd Annual Report - For the Year Ended March 31, 2014

Manitoba Hydro

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Cover: Rebuilding the 95-year-old Stafford Street Station in Winnipeg.

July 31, 2014

Honourable Stan Struthers
Minister charged with the administration of the Manitoba Hydro Act
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Minister:

I have the honour of presenting the 63rd Annual Report of the Manitoba Hydro-Electric Board, together with the financial statements, for the fiscal year ended March 31, 2014.

Respectfully submitted,

William C. Fraser, FCA
Chair, Manitoba Hydro-Electric Board

Corporate profile

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. We provide reliable, affordable energy to customers throughout Manitoba and trade electricity within three wholesale markets in the Midwestern United States and Canada. Nearly all of the electricity Manitoba Hydro produces each year is clean, renewable hydro power generated using the province's abundant water resources. We are also a leader in promoting conservation, providing a suite of Power Smart* programs to help our customers get the most out of their energy dollar.

Vision

To be recognized as a leading utility in North America with respect to safety, reliability, rates, customer satisfaction and environmental leadership.

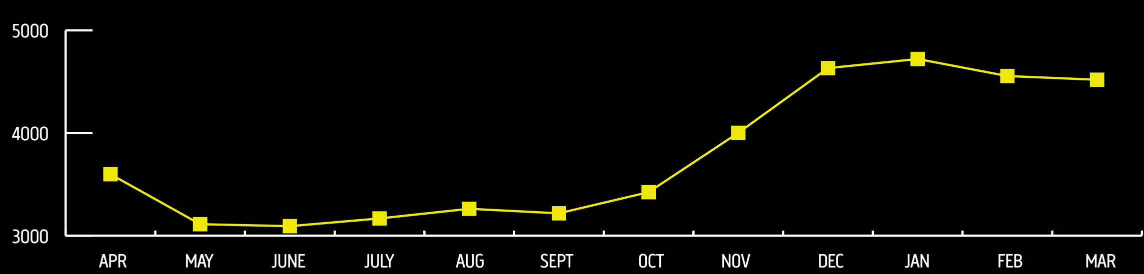
Mission

To provide for the continuance of a supply of energy to meet the needs of the province and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy.

5 725 megawatts
Total electricity capability

536 081
billion joules
Peak natural gas load

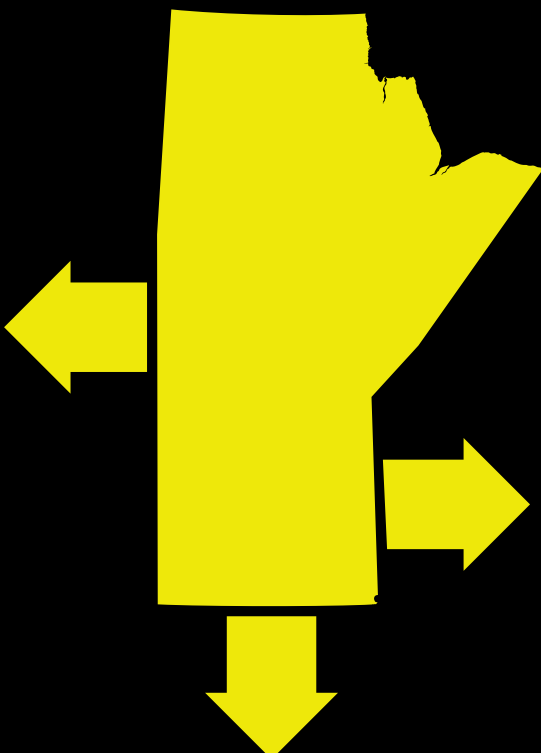
4 720
megawatts
Peak Manitoba electricity load



*Manitoba Hydro is a licensee of the Trademark and Official Mark.

$439 million

Revenue from export sales of electricity



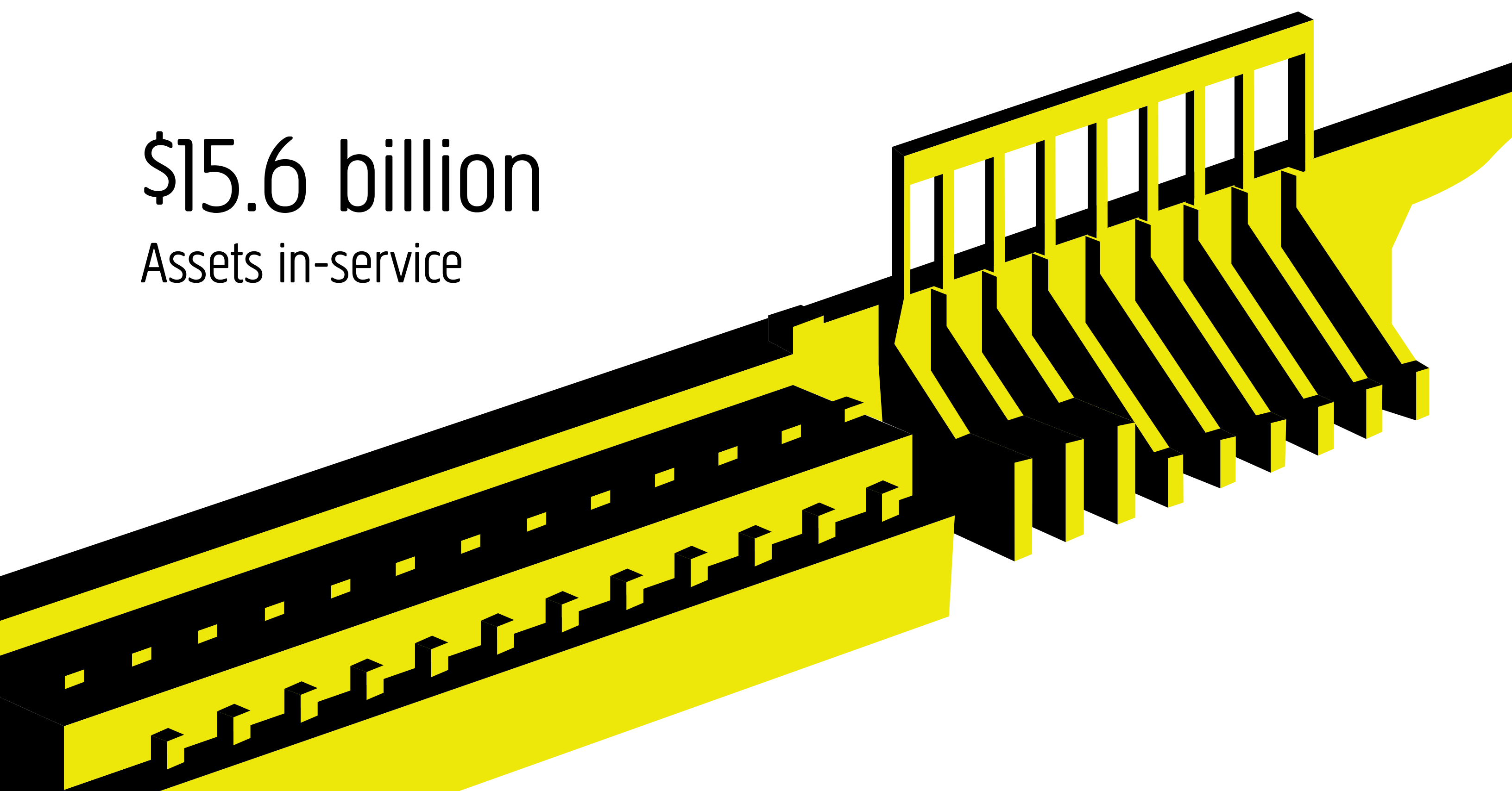
6 556 Full-time employees

$1.9 billion

Revenue from Manitoba sales of electricity and natural gas

$15.6 billion

Assets in-service



Chair's message

Manitoba Hydro is working to preserve a legacy of affordable energy and derive value from the province's abundant renewable energy resources for all Manitobans.

This past year saw the successful completion of negotiations with Wisconsin Public Service resulting in two new power sales; one for 108 megawatts from 2016 to 2021 and another for 308 megawatts for up to 10 years starting in 2027. These agreements bring the total value of Manitoba Hydro's recently signed export contracts to over $9 billion. Electricity rates in Manitoba would be considerably higher without export sales, so continuing to pursue further opportunities must be a priority. To that end, Manitoba Hydro signed memorandums of understanding to investigate future sales of up to 600 megawatts with Great River Energy of Minnesota and 500 megawatts with SaskPower.

The corporation also continued moving forward with plans to develop new sources of clean, renewable hydroelectricity in the north. The

Electricity rates in Manitoba would be considerably higher without export sales, so continuing to pursue further opportunities must be a priority.

Keeyask Generating Station will be built, pending necessary approvals, in partnership with four First Nations – Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. Through this approach, first undertaken with the Wuskwatim Generating Station, First Nations people who live in the

directly affected area are involved in the planning of the project, take part in the development and have access to its benefits. A recent independent assessment of Keeyask under the Hydropower Sustainability Assessment Protocol concluded the project was a prime example of sustainability, in part, because of the extensive participation by the First Nation partners.

The five First Nations in the vicinity of the proposed Conawapa Generating Station also have an opportunity to participate in that project. Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, Shamattawa First Nation, War Lake First Nation and Manitoba Hydro are already collaborating on planning and environmental studies. In addition, agreements related to potential training, employment, business and income opportunities are being negotiated.

The board was also pleased to see the start of construction on the Bipole III transmission project that will benefit all of Manitoba by strengthening the reliability of the province's electricity supply and providing additional capacity needed to deliver electricity from new northern generating stations to southern Manitoba. The Manitoba Environment Act license for Bipole III was issued in August.

I and my fellow board members are tasked with ensuring Manitoba Hydro carries out its legislated mandate to meet the energy needs of the province in an economic and efficient manner. To accomplish this, board members participate in audit, human resources and governance, and planning committees. We advise management as it decides on strategic objectives and approve major capital projects.

I would like to express my appreciation to all board members for their attentive efforts over the past year.

Manitoba Hydro's performance, both financially and operationally, is worthy of praise. It attests to diligent management and effective employees. I thank all employees for their contributions to Manitoba Hydro's success.

William C. Fraser, FCA
Chair
Manitoba Hydro-Electric Board

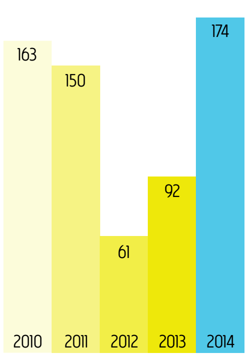
President & CEO's message

The past fiscal year saw many achievements by Manitoba Hydro. The corporation booked a higher than forecast consolidated net income of $174 million that increased retained earnings to $2.72 billion, the highest level of equity in our history. This $82 million improvement over the previous year's net income was the result of higher volumes in export electricity sales, higher export prices and increased consumption arising from a much colder winter.

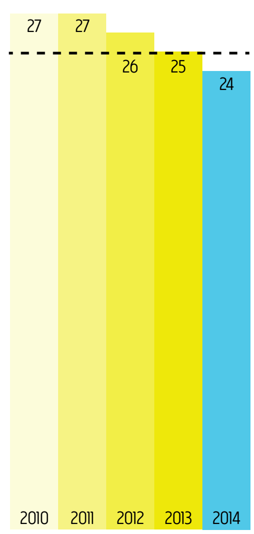
The coldest winter in 116 years pushed parts of our system to the edge with many of our electric transmission and distribution stations operating at or near the limits of their capacity. Yet there was little impact on our service, thanks to the effective planning and balancing of loads by our staff.

Manitoba Hydro also took major steps forward in our plan for meeting the growing energy needs of this province. We prepared and submitted the business case for our preferred development plan to the Manitoba Public Utilities Board, who subsequently conducted a public Needs For and Alternatives To review. We also participated with our four First Nation partners in the Clean Environment Commission's review of the environmental impact statement for the planned Keeyask Generating Station.

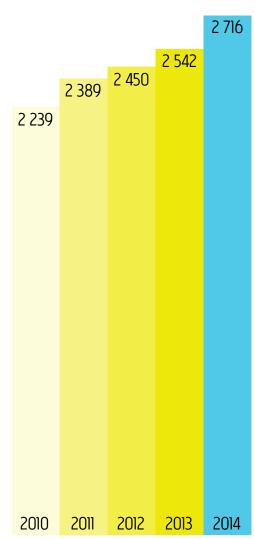
However, what stands out for me personally are the extraordinary efforts of our employees — the men and women who worked long hours, giving up weekends and family time, to prepare for and participate in various regulatory hearings; those who worked tirelessly in January to support our customers in south central Manitoba during a four-day loss of supply from TransCanada Corporation's main pipeline; or the 42 individuals who selflessly gave up their Christmas holiday to



Net Income (millions of dollars)



Equity Ratio - For the year ended March 31
Target - - -



Retained Earnings - For the year ended March 31
millions of dollars

help the people of Toronto regain power after a devastating ice storm.

These examples demonstrate the character of our employees and the commitment to service that permeates this organization. This proves to me that we have the team to successfully re-power our province.

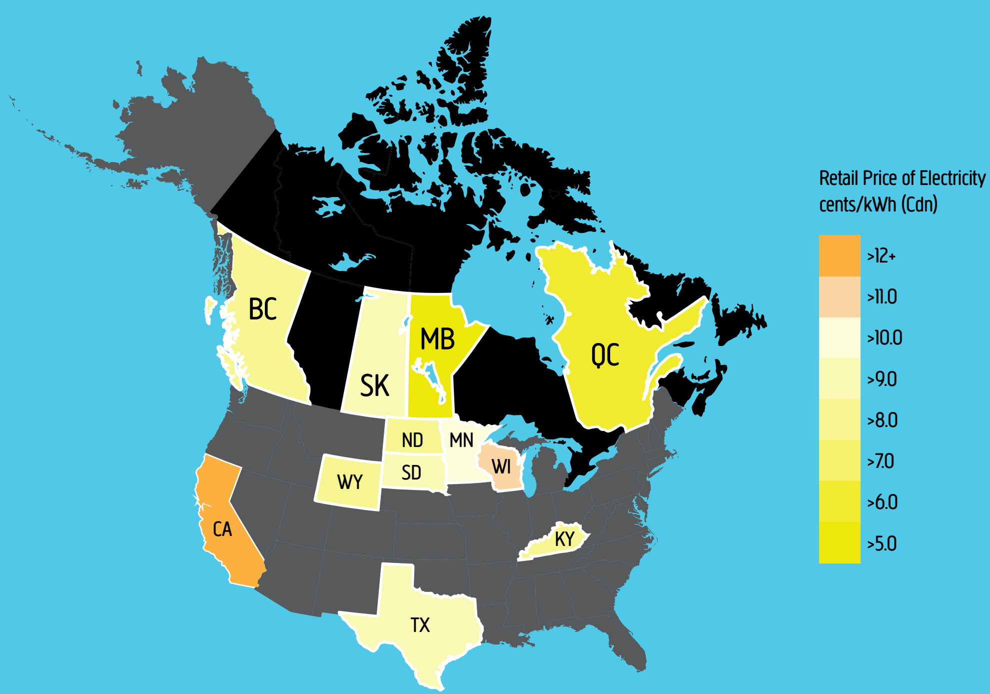
Demand is growing by about 80 megawatts a year and Manitoba needs new sources of electricity by about 2023. We have evaluated different scenarios involving population growth, economic growth and demand side management but these variables only affect the timing for new generation by a few years. Given the long lead times required to develop new generating stations, we are at a point where a decision must be made on how Manitoba Hydro will fulfill its obligation to meet the province's future electricity needs.

Our preferred development plan includes two projects that will proceed immediately, pending necessary regulatory approvals: the 695-megawatt Keeyask Generating Station to be in-service in 2019 and a new 500 000-volt transmission interconnection to Minnesota with an in-service date of 2020. It also includes the 1 485-megawatt Conawapa Generating Station with a projected in-service of 2026; however, a decision to proceed with this project is not required until 2018 and Conawapa will only be built if the business case remains sound.

At the same time, many of Manitoba Hydro's generation, transmission and distribution assets are approaching the end of their service life and becoming more costly to maintain. The risk of equipment failure is growing and outages may become more frequent and last longer if adequate investment is not made to upgrade and renew these facilities. In Winnipeg, for example, 20 distribution substations need

Retail Price of Electricity - cents/kWh (Cdn)

6.4	Manitoba
6.4	Quebec
8.0	British Columbia
8.5	Wyoming
8.6	Kentucky
8.9	North Dakota
9.1	Saskatchewan
9.5	South Dakota
9.7	Texas
10.3	Minnesota
11.3	Wisconsin
15.0	California



Deregulated jurisdictions such as Alberta and Ontario are not included in this comparison as there are numerous utilities providing service in each province, making it difficult to derive an overall bundled average retail rate that includes generation, transmission and distribution service.

President & CEO's message

to be replaced or refurbished by 2020. Other assets in need of renewal across the province include wooden distribution poles, underground electric cables and manholes.

The reality is electricity rates in Manitoba must rise to ensure the ongoing safety and reliability of our electricity supply and delivery system. It's a story repeating itself across North America as other utilities address aging infrastructure and growing demand. The British Columbia government announced that electricity rates will increase by nine percent in 2014 and six percent in 2015. SaskPower proposed rate increases of 5.5 percent in 2014 and five percent in each of 2015 and 2016. The Ontario government's 2013 Long Term Energy Plan indicates residential customers in that province could see their bills increase by 9.6 percent in 2014, 5.8 percent in 2015 and 15 percent in 2016.

The challenge facing Manitoba Hydro is balancing the needed investment in our system with maintaining the financial health of the corporation and providing stable, predictable rates for our customers.

Manitoba's electricity rates continue to be among the lowest overall in North America. That is due, in large part, to the corporation's past investments in developing hydroelectric generating stations and to the revenue that's been earned by selling surplus electricity from those stations into the export market. Those revenues totaled $439 million in 2013-14, 23 percent of our total electricity revenue for the fiscal year.

Manitoba Hydro's plan for re-powering our province builds on this legacy and will allow us to make needed investments and maintain financial strength through reasonable, gradual electricity rate increases that will provide adequate revenues and avoid the need for higher rate increases in the future.

The generation resources in our preferred development plan are supported by a number of export agreements, including a 250-megawatt sale to Minnesota Power plus a 108-megawatt sale and a 308-megawatt sale to Wisconsin Public Service. These long-term agreements, along with forecast domestic demand growth, have essentially sold out the surplus associated with the Keeyask Generating Station. They also reflect prices substantially more attractive than those in our existing firm export contracts and will help reduce the costs of building new generation supply for Manitoba ratepayers.

In addition, our plan includes a substantially increased investment in demand side management. New and expanded Power Smart programs will aggressively target additional electricity and natural gas savings, helping our customers reduce their energy costs. Manitoba Hydro customers have saved over $860 million since the Power Smart program was launched in 1991.

The challenge facing Manitoba Hydro is balancing the needed investment in our system with maintaining the financial health of the corporation and providing stable, predictable rates for our customers.

Balancing the financial health of Manitoba Hydro with reasonable rates will also require a concerted effort to control costs within the corporation. One measure already implemented is the evaluation of positions vacated by retirements to determine whether they need to be filled or if we can change the way we work. It's an opportunity created by the demographics of our workforce — over 900 employees are eligible to retire in 2014. However, we need to ensure staffing levels are adequate to provide safe and reliable service. We also need to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors.

This last point was brought home this past year with the retirement of two members of our executive team. Ken Adams and Ed Tymofichuk both brought vast experience to their roles and contributed greatly to Manitoba Hydro's success over their long careers. Ken, who retired as Vice-President of Major Capital Projects, was instrumental in setting the course for recent and planned supply-side additions, including the precedent setting partnership with Nisichawayasihk Cree Nation to build the Wuskwatim Generating Station. Ed, who retired as Vice-President of Transmission, helped to lead the corporation through a number of key projects including a new system control centre and regulatory approval for the Bipole III transmission project. I would like to thank both of them for their outstanding service and support over the years.

I also want to thank the members of the Manitoba Hydro-Electric Board and particularly the Chair, Bill Fraser, for the support and counsel provided over the past year.

Finally, I want to express my gratitude for the contribution of our employees. Their dedication and commitment demonstrated over the past year is what will allow us to meet the challenge of continuing to provide the value and reliability our customers have come to expect from their energy utility.

Scott A. Thomson, CA
President and Chief Executive Officer
Manitoba Hydro

Year in review

FINANCIAL RESULTS

	Electricity		Natural Gas		Consolidated		Change
	2014	2013	2014	2013	2014	2013	
Revenue							
			millions of dollars				
Manitoba	1 475	1 410	415	329	1 890	1 739	151
Extraprovincial	439	353	-	-	439	353	86
	1 914	1 763	415	329	2 329	2 092	237
Cost of gas sold	-	-	252	182	252	182	70
Expenses	1 782	1 692	143	139	1 925	1 831	94
Net income before non-controlling interest	132	71	20	8	152	79	73
Net loss attributable to non-controlling interest	22	13	-	-	22	13	9
Net income	154	84	20	8	174	92	82
Retained earnings	2 654	2 500	62	42	2 716	2 542	174

OPERATING STATISTICS

	2014	2013	Increase/(Decrease)
Electrical Operations			
Sales	*billions of kilowatt hours*		
Manitoba sales	22.4	21.5	0.9
Extraprovincial sales	10.5	9.1	1.4
System supply	*billions of kilowatt hours*		
Generation	35.4	33.2	2.2
Purchases	1.5	1.4	0.1
	thousands of kilowatts		
Manitoba peak load	4 720	4 535	185

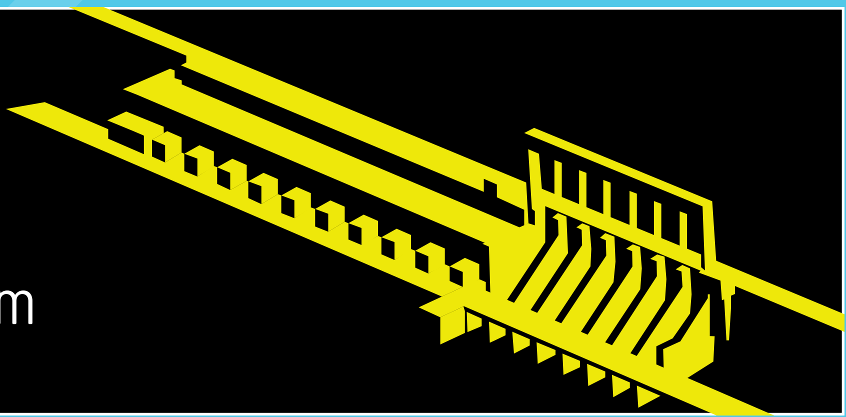
	2014	2013	Increase/(Decrease)
Natural Gas Operations			
	millions of cubic metres		
Residential sales	664	602	62
Commercial and industrial sales	964	849	115
	1 628	1 451	177
Transportation service	652	598	54
	2 280	2 049	231
	billions of joules		
Manitoba peak load	536 081	504 961	31 120

Harnessing resources

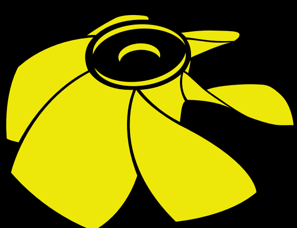
Manitoba Hydro operates 15 hydroelectric generating stations that harness the energy of the province's rivers to meet the electricity needs of our customers. We also maintain two small thermal generating stations and purchase power from two independent wind farms to support this hydroelectric system.

$714 million

Invested to build and maintain generation system



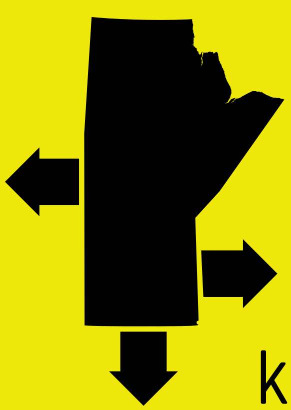
Total hydraulic generation: 35.3 billion kilowatt hours



Total Manitoba sales:

22.4 billion kilowatt hours

Total export sales:



10.5 billion kilowatt hours

Surveying the Pointe du Bois Spillway Replacement Project on the Winnipeg River.

Harnessing resources

Reviewing preferred development plan

Public hearings on Manitoba Hydro's plan for meeting the future electricity needs of the province began in March 2014. The hearings are part of a Needs For and Alternatives To review by the Manitoba Public Utilities Board (PUB) aided by a number of independent expert consultants from across North America.

The corporation's preferred development plan includes the 695-megawatt Keeyask Generating Station, a new 500 000-volt transmission interconnection with Minnesota, additional export sales and aggressive demand side management. The plan also protects the option to build the 1 485-megawatt Conawapa Generating Station subsequent to Keeyask. The 5 000-page business case for the preferred plan submitted to the PUB in August 2013 describes the extensive process used to arrive at a short list of viable options and presents an in-depth analysis of 15 alternative development plans over 27 scenarios involving 400 cases. It concludes that the preferred development plan meets Manitoba's electricity needs at the lowest cost to ratepayers over the long-term and provides the greatest benefits to the province.

Subsequent to the August filing, a substantial amount of information and analysis was provided to the PUB on three additional levels of demand side management, including a further 19 alternate development plans. Nearly 50 days of hearings were scheduled involving five registered interveners, 31 consultants and more than 20 presentations by the public. The hearings are expected to end in May with a report submitted to the minister responsible for the Public Utilities Board Act by no later than June 20.

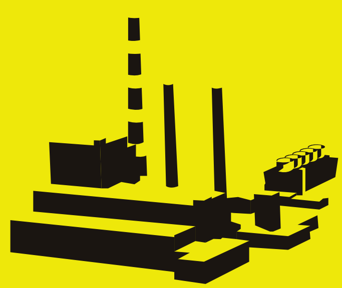
Concluding Keeyask environmental review

The Manitoba Clean Environment Commission conducted a public hearing on the planned Keeyask Generating Station as part of an environmental licensing review. Thirty-eight days of public hearings on the project's environmental impact statement concluded in January and the commission was expected to submit a recommendation report within 90 days to the Minister of Manitoba Conservation and Water Stewardship.

The $6.5-billion Keeyask Generating Station is being developed, pending regulatory approvals, by the Keeyask Hydro Power Limited Partnership consisting of the four Keeyask Cree Nations — Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, York Factory First Nation — and Manitoba Hydro. The site for the station is on the Nelson River approximately 30 kilometres west of Gillam within the Split Lake Resource Management Area. Once completed, the Keeyask Generating Station will provide an average of 4.4 billion kilowatt hours of renewable energy each year.

Sources:

hydroelectric 95.4%



thermal 0.4%

In March, the general civil contract for Keeyask was awarded to a limited partnership between Bechtel Canada, Barnard Construction of Canada and EllisDon Civil. Pending regulatory approvals, construction is scheduled to start in the summer of 2014 with an in-service of 2019.

The majority of the infrastructure required to support construction of Keeyask, including an all-weather access road and the first phase of the main construction camp, was near completion at the end of the fiscal year. An early start to construction of this infrastructure was undertaken to minimize risk of delays and to optimize employment, training and business opportunities for the Keeyask Cree Nations. Multiple training opportunities at site included specialized, on-the-job training programs for road construction, work-site area development, catering/housekeeping, security, emergency medical services and camp maintenance. A range of apprentices also acquired work experience on main camp construction.

Planning for Conawapa

Preparatory engineering, environmental and consultation work for Conawapa, the other generating station in Manitoba Hydro's preferred development plan, continued throughout the fiscal year to protect a construction start date of 2018 and an earliest in-service date of 2026. Environmental and Aboriginal Traditional Knowledge studies are underway with the intent of having the environmental impact statement finalized and available to file with regulators by the end of 2015.

The Conawapa Generating Station would be built on the Nelson River, about 90 kilometres downstream of Gillam, in the Fox Lake Resource Management Area. When complete, Conawapa will produce an average of seven billion kilowatt hours of electricity annually, making it the largest generating station in Manitoba.

A formal planning process is underway with the communities in the vicinity of the proposed generating station, including Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, War Lake First Nation and Shamattawa First Nation. An agreement related to ownership of the station, income and business opportunities was reached with Fox Lake Cree Nation in June 2013. Discussions have been ongoing with Fox Lake regarding project opportunities. A memorandum of understanding between Fox Lake Cree Nation, the Province of Manitoba and Manitoba Hydro recognizes that Fox Lake will have a leading and significant role in the planning process of the Conawapa Generating Station because of its proximity to the community.

Realizing export opportunities

Manitoba Hydro's strategy of growing export revenues to keep our customer's electricity rates lower than they would be otherwise and defray some of the costs for new generating

Purchases excluding wind 1.7%

Harnessing resources

stations resulted in a number of power sale agreements in 2013-14.

A 200-megawatt seasonal diversity exchange with Great River Energy of Minnesota was signed in July, extending a 150-megawatt arrangement that has been in place since 1995. The new agreement runs until 2030.

In September, Manitoba Hydro and SaskPower executed a 25-megawatt term sheet to supply firm power to Saskatchewan's far north from 2015 to 2022. The two utilities also signed a memorandum of understanding to investigate a potential 500-megawatt sale that would begin after 2020.

In December, Manitoba Hydro and Minnesota Power signed a 50-megawatt firm power sale from 2015 to 2020, replacing an existing 50-megawatt arrangement that expires in 2015.

In February, two major power sales to Wisconsin Public Service were announced. The first sale running from 2016 to 2021 is for 108 megawatts of firm power. The second sale, which would use electricity produced by the proposed Conawapa Generating Station, is for 308 megawatts of firm power for up to 10 years starting in 2027. The 308-megawatt sale also requires a new 500 000-volt transmission interconnection to Minnesota. A 100-megawatt sale to Wisconsin Public Service announced in 2011 is scheduled to run from 2021 to 2026, bridging the gap between the two new deals.

Also in February, a memorandum of understanding was signed to jointly investigate the sale of up to 600 megawatts of electricity from Manitoba Hydro to Great River Energy commencing in approximately 2020.

Upgrading spillway at Pointe du Bois

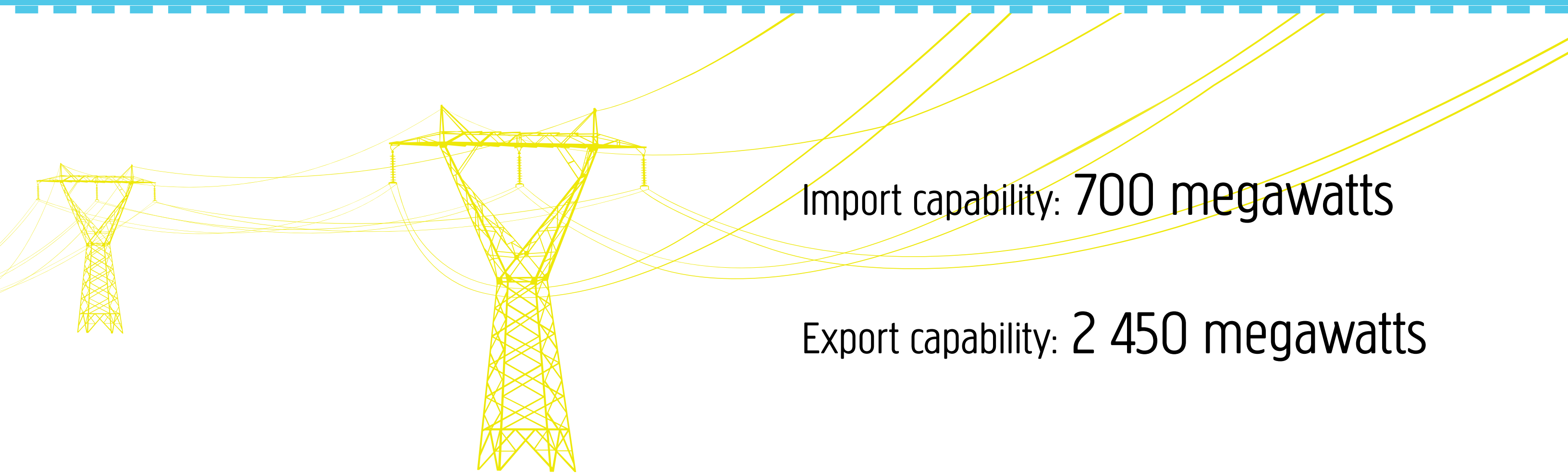
Nearly all of the existing spillway bays or sluiceways at the Pointe du Bois Generating Station have to be manually operated, a difficult task in icy conditions. The $560-million Spillway Replacement Project will replace these century-old structures with a seven-bay spillway and earth-fill dam, providing a safer work environment for Manitoba Hydro employees. The new spillway structure will also increase the station's flood capability to meet the Canadian Dam Association's dam safety guidelines.

Installation of gates as well as the mechanical and electrical systems for the new spillway structure was ongoing at the end of the fiscal year.

Rehabilitating existing generators

Generators at a number of Manitoba Hydro's older stations were rehabilitated during the fiscal year.

A seven-year project to recondition all of the Kelsey Generating Station's units was completed in July when the last unit was returned to service. The Kelsey Re-runnering



Import capability: 700 megawatts

Export capability: 2 450 megawatts

Project increased the station's total output by approximately 77 megawatts at a cost of $300 million. The work included rewinding of the stators and rotors, modifications to the draft tubes and installation of new turbine runners.

At the Pointe du Bois Generating Station, a unit was returned to service after rehabilitation of the runner-shaft coupling assembly, repairs to the runner and refurbishment and replacement of other turbine components. Work is continuing on three other units which are expected to be returned to service by the summer of 2015.

At the Great Falls Generating Station, a unit was returned to service following replacement of a failed generator stator. The project included installing a new stator, refurbishment of the rotor and various other improvements.

Work is also underway at the Pine Falls Generating Station to rewind a failed stator and refurbish the rotor field poles on a unit. The work is expected to be completed in July 2014.

Representatives of Manitoba Hydro and the Keeyask Cree Nation Partners at public hearings to review the corporation's preferred development plan.

Enhancing reliability

Manitoba Hydro maintains a vast network of electric transmission and distribution lines, as well as natural gas distribution pipelines, to deliver energy across the province. This network includes 12 electric transmission interconnections with neighbouring utilities.

76 000 km

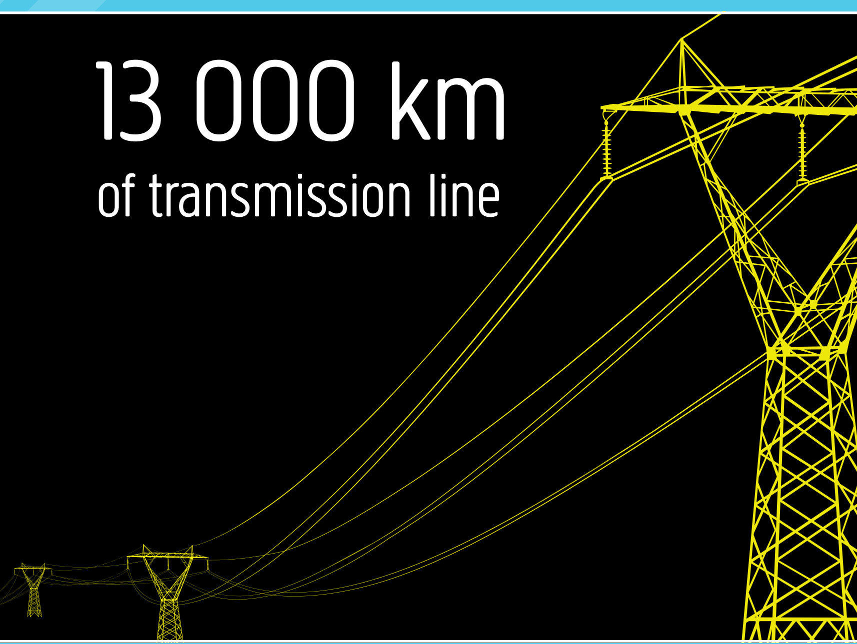
of distribution line

$663 million

Invested to build and maintain delivery system

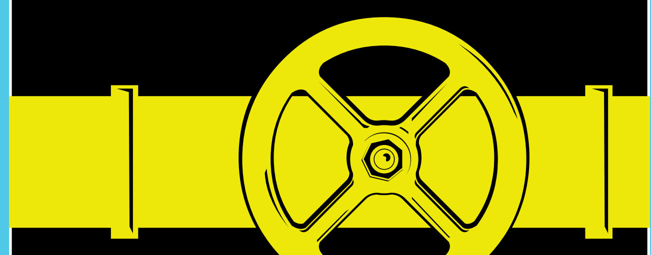
13 000 km

of transmission line



9 700 km

of natural gas pipeline



Commissioning the new Riel Terminal Station east of Winnipeg.

Enhancing reliability

Building reliability with Bipole III

Construction began this past winter on Bipole III, a new high voltage direct current transmission line required to enhance Manitoba Hydro's system reliability. The Manitoba Environment Act license for Bipole III was issued in August after a rigorous public hearing on the project's environmental impact statement and a subsequent report by the Clean Environment Commission.

The Bipole III project includes: a 1 384-kilometre, 500 000-volt direct current transmission line; the Keewatinoow Converter Station near the site of the proposed Conawapa Generating Station, and the Riel Converter Station on the east side of Winnipeg. These facilities will back-up the Bipole I and II high voltage direct current transmission systems, which share a common right-of-way corridor, and the Dorsey Converter Station. Dorsey is the only outlet in southern Manitoba for hydroelectricity generated on the lower Nelson River — the source of over 70 percent of the electricity produced in the province. Bipole III will also provide additional capacity for delivery of electricity from the proposed Keeyask and Conawapa generating stations to southern Manitoba.

In January, work began on clearing the right-of-way in northern sections between Thompson and The Pas. Work also got underway on a line to provide construction power to the site of the Keewatinoow Converter Station. This work was being done under a direct negotiated contract with a joint venture partnership between Fox Lake Cree Nation and Valard Construction.

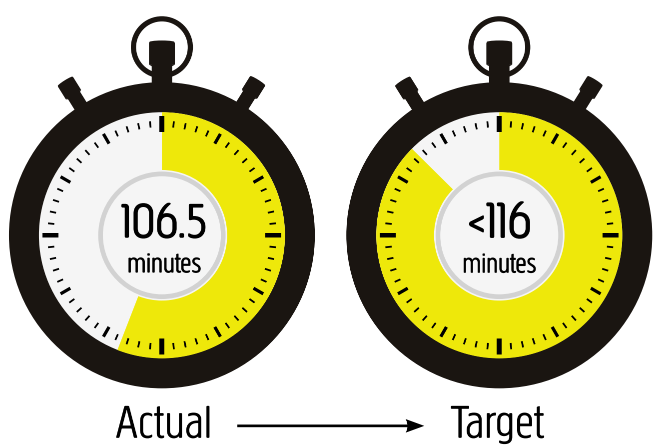
Engaging on transmission routes

In November, Manitoba Hydro began seeking public input to be used in route selection and environmental assessment for the proposed Manitoba-Minnesota Transmission Project. The project, which is part of the corporation's preferred development plan, includes a 500 000-volt alternating current transmission line originating at the Dorsey Converter Station near Winnipeg then heading south to the Manitoba-Minnesota border where it will connect to the Great Northern Transmission Line to be built by Minnesota Power. Along with providing additional opportunities for export sales to the U.S., the new line will provide increased reliability for Manitoba's energy supply, allowing for the import of additional electricity during emergency outages or droughts. Manitoba Hydro expected to file an environmental impact statement for the project in 2015. Subject to regulatory approvals, the project's planned in-service date is mid-2020.

Public input was also sought on two proposed 230 000-volt transmission lines, both originating at the St. Vital Transmission Station in southwest Winnipeg. These new transmission lines will improve system reliability and accommodate growth in electricity demand in south central Manitoba. The St. Vital to Letellier line is expected to be in-service in 2017. The St. Vital to La Verendyre line is expected to be in-service

System average interruption duration

(minutes per year).



in 2018. A preferred route was presented to the public in November. Feedback is being compiled to finalize the route and complete the environmental assessment. A report on the project is expected to be submitted to Manitoba Conservation and Water Stewardship in mid-2014.

Completing new terminal for key interconnection

The Riel Terminal Station was nearing completion at the end of the fiscal year with commissioning of the control system underway. The new alternating current terminal will create a second point where electricity imported from the United States on an existing 500 000-volt transmission line can be introduced into Manitoba Hydro's transmission network. Undertaken to reduce dependence on the existing terminal station at Dorsey, the Riel Terminal Station will improve the reliability of the province's energy supply, protecting against prolonged outages to existing termination facilities or droughts.

Located just east of Winnipeg, the Riel Terminal Station is expected to be in-service in 2014 at a cost of $330 million. Bipole III will also terminate at the Riel site and include the addition of converters and ancillary equipment.

Expanding capacity with new stations

Work progressed on the replacement of aging, capacity-constrained transmission and distribution stations during the fiscal year. Foundation and building construction was underway at the end of March for the new Rockwood East Transmission Station north of Winnipeg. The station will increase capacity and eventually replace the 1940s-era Parkdale Station. Erection of steel structures and installation of electrical equipment was also underway at a new transmission station near Neepawa. Needed to meet forecast load growth in the area, the station is scheduled to be in-service in 2015.

Of the 97 distribution substations in Winnipeg, Manitoba Hydro expects to replace or refurbish 20 by 2020. The new Martin Avenue substation in Winnipeg was under construction adjacent to a substation which was built in the 1950s and is no longer adequate to meet the area's electricity needs. Groundwork began in March 2013 and the new substation is scheduled to enter service in late 2014. The new Burrows substation in Winnipeg's north end was placed in-service during the year. Work continued to convert the distribution lines emanating from the new station to a higher capacity 12 470-volt design from the existing 4 160-volt. When the conversion project is complete, the Burrows substation will replace three substations which were over 60 years old and had reached the limit of their capacity.

Preliminary design work was underway on a new substation to replace the St. James substation located on the corner of Portage Avenue and St. James Street in Winnipeg. The Madison substation will address reliability concerns arising from the aging infrastructure at the existing substation and provide more capacity to serve the growing number of commercial and industrial customers in the area. Construction of the Madison substation is expected to begin in the summer of 2014 with an expected in-service of 2016. Design work also began for an expansion of the York Street substation that will see the addition of three transformer banks and sets of 12 470-volt switchgear. The project, which will accommodate projected load growth in downtown Winnipeg, is expected to be in-service by summer of 2016. Planning began for the new Adelaide substation which will replace the King Street substation in Winnipeg's market district. The King Street substation building is over 100 years old and no longer adequate to meet reliability and safety requirements. The expected in-service for the Adelaide substation is spring 2017.

In rural Manitoba, a number of distribution supply centres were under construction to support increased electricity demand. Distribution supply centres are complete

Enhancing reliability

substations, with all the components pad-mounted and conductors buried underground, which can effectively serve areas with lower load densities. The result is a sleek, compact design with less visual presence than a traditional, wood-pole and steel substation. New distribution supply centres are being built east of Kleefeld, at Selkirk, near Lockport and in McTavish near Morris.

Beginning manhole rebuilds

A concerted effort began under the streets of downtown Winnipeg in the last year to rebuild manholes which are an important part of Manitoba Hydro's electrical distribution system. The corporation has approximately 2 400 manholes throughout the province with over 1 800 in downtown Winnipeg. Some of these enclosures are over 100 years old. An engineering survey identified approximately 350 manholes in need of rehabilitation or replacement within the next 20 years at an estimated cost of $52 million. Priority is being given to manholes located on public roadways because they are subjected to the most severe conditions and present the highest risks to the public.

Injecting new life into aging cables

A pilot project explored the logistics and costs associated with using injected silicone to extend the life of aging underground electricity distribution cables. Manitoba Hydro has over 6 000 kilometres of underground electric cable, approximately 3 300 kilometres of which is a cross link polyethylene insulated variety installed between 1970 and 1986 that has started to reach the end of its useful life.

The injection method forces silicone under pressure into the cable's strands of conductors flushing out impurities and encapsulating any moisture within the insulation sheathing. The process can extend the life of the cable by up to 40 years. It is also significantly less expensive and quicker than replacing the cable outright which involves significant labour and disruption to property owners. The pilot study concluded that the average cost of silicon injection was about five times less per metre than the cost of traditional cable replacement. Based on these results, the corporation began a more comprehensive silicone cable injection program to address its aging cable infrastructure.

Upgrading natural gas pipeline

A new pipeline was installed in south central Manitoba providing additional capacity needed to meet increased natural gas usage and community growth. The 14.5-kilometre, 114.3-millimetre diameter steel pipeline runs from a point approximately four kilometres west of Letellier to St. Jean Baptiste. Construction began in August and was completed in October.

Average electric customer outage (frequency per year) 1.3

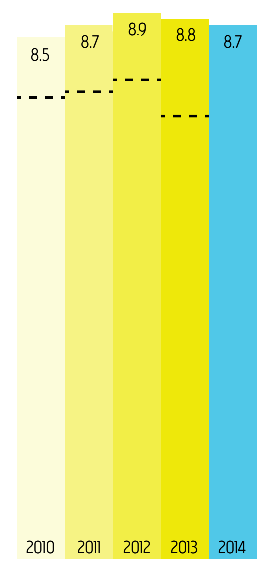
To provide additional capacity needed to maintain natural gas service for the growing community of Headingly and support future growth in the area, a new natural gas pipeline was installed in the Rural Municipality of St. Francois Xavier. The project included 19 kilometres of new 168.3-millimetre steel pipeline connecting a natural gas station on Selkirk Avenue in Winnipeg to a new pressure regulation station in the municipality and an additional four kilometres of 219.1-millimetre polyethylene pipe connecting to an existing distribution pipeline west of Headingly. The pipeline installation and construction of the new station began in June and was completed in November.

Much of the planning and design work for upgrades to the Winnipeg natural gas transmission network was completed. Serving over 213 000 natural gas customers in Winnipeg and areas to the north, the network consists of four pipelines. The Winnipeg Northwest Upgrade Project will provide additional redundancy in supply and balance loads on the primary stations feeding Winnipeg. Phase one of the project, which includes installation of a new pressure regulating station near St. Andrews to support local growth in demand, will be completed in 2014-15.

Mitigating ice formation

Rising moisture content in natural gas supplied to Manitoba Hydro is increasing the risk of operational problems and outages. In response, the corporation initiated an analysis of available line heater technologies that can prevent freeze-off and ice formation. The analysis will evaluate supply and installation costs as well as predicted annual energy and maintenance costs. Plans were to complete designs for line heaters at two sites based on selected technologies and begin installation in 2015.

Customer Satisfaction with System Reliability (electricity)
(Source: MH quarterly customer satisfaction tracking study)



CEA average for all Canadian electric utilities
* CEA data for 2014 unavailable.

Serving customers

Recognized as an industry leader in customer satisfaction, Manitoba Hydro is committed to providing superior service and ensuring exceptional value for our customers.

Electricity customers: 555 760

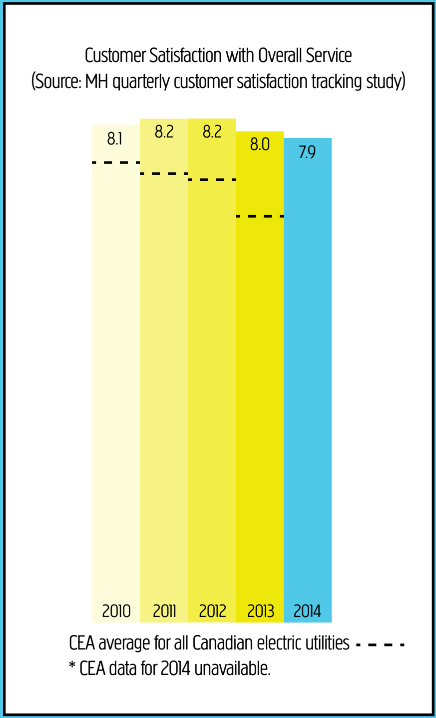
Natural Gas customers: 272 228

Cumulative Power Smart energy savings (electric):

2.48 billion kilowatt hours

Cumulative Power Smart energy savings (natural gas):

88.3 million cubic metres



Preparing to replace a decayed cross-arm.

Serving customers

Extending Power Smart's reach

For over two decades Manitoba Hydro has been finding ways to help customers reduce energy use and lower their bills. That innovation continued in 2013-14 with the introduction of two new Power Smart initiatives.

The Power Smart for Business Pay As You Save (PAYS) Financing Program for commercial customers was launched in September. Working in conjunction with the full suite of Power Smart for Business incentive programs, PAYS provides attractive financing to help mitigate the capital cost barrier often associated with upgrading to an energy efficient technology. Financing is available with 10- to 25-year amortizations, depending on the energy efficiency upgrade, as long as the monthly repayment for the upgrade is less than the estimated annual utility savings calculated on an average monthly basis. Some of the energy efficiency upgrades eligible for financing with PAYS include insulation, LED lighting and geothermal heat pump systems.

In June, Manitoba Hydro introduced a new program that seeks to install geothermal heat pump systems on a mass scale throughout First Nation communities where homes typically use electric heat. The Power Smart Community Geothermal Program provides technical guidance, energy bill assessments and utilizes the residential PAYS Financing Program so community members can pay for the majority of the system through energy savings realized by the conversion to geothermal.

Through a partnership with Aki Energy, a non-profit social enterprise group, the Community Geothermal Program also created employment opportunities within First Nation communities. Community residents were trained in the installation and ongoing maintenance of the geothermal systems. This training was funded by the First Nations themselves. In 2013, 108 geothermal installations were completed in Fisher River Cree Nation and Peguis First Nation. At the end of the fiscal year, discussions were underway with four other First Nations on participation in the program.

Helping customers save

Manitoba Hydro offered 30 Power Smart programs including 16 for customers in the commercial sector and five for the industrial sector.

The Power Smart Bio-energy Optimization Program, for example, helped industries to use new technologies that convert waste streams into energy sources. These technologies can replace energy purchases from Manitoba Hydro and lower operating costs. Tundra Oil and Gas utilized the program to install three micro-turbines that use flare gas to generate electricity at the company's oil and gas battery site near Cromer, Manitoba. The battery site receives

Investment in Power Smart programs:

$34 million

crude oil from surrounding wells and then removes the water and petroleum gases. The water is injected back into the oil producing formation and the petroleum gas is typically flared at site. The micro-turbines are capable of using that gas to generate 180 kilowatts and supply 1.4 million kilowatt hours of energy per year. The Bio-energy Optimization Program supported the project's feasibility study as well as the implementation phase.

The Performance Optimization Program helped Boeing Canada to identify improvements to the compressed air system at their Winnipeg manufacturing facility. A new energy efficient compressed air production and treatment system was installed that included multiple screw compressors, larger storage reserves, cycling dryers and sequenced compressor controls. In addition to installation of new equipment, an aggressive compressed air leak management and repair program further reduced energy use. The resulting efficiency improvements increased reliability at the plant and cut the energy costs of operating the compressed air system by 80 per cent, enabling Boeing to achieve load reductions of 583 kilowatts and annual energy savings of approximately 4.1 million kilowatt hours.

The community of La Salle worked with Manitoba Hydro to design and build a new community centre in accordance with Power Smart Design Standards. The 1 600 square metre multipurpose recreation and fitness centre is at least 33 per cent more efficient than a typical centre with features such as: high levels of roof, wall and floor insulation; ventilation heat recovery; energy efficient lighting fixtures; and a high efficiency condensing hot water tank. The corporation provided technical advice as well as financial incentives through the Power Smart New Buildings Program.

Modernizing the service model

As part of an ongoing effort to modernize operations, Manitoba Hydro began consolidating rural district offices in southern Manitoba into regional customer service centres to improve customer service and reduce costs. At the end of the fiscal year, 19 of the corporation's district offices closed with an additional five offices slated to close by the end of the 2016-17 fiscal year. When complete, the consolidation is expected to reduce costs by approximately $2 million annually and avoid another $50 million in costs associated with needed facility upgrades to the 24 affected locations.

Since 2007, there has been a steady decline in customer transactions at district offices and a corresponding shift to using customer service centres or making bill payments online or by phone. The consolidation of staff will allow Manitoba Hydro to use resources more efficiently, while maintaining service levels to all customers. It will also further optimize the corporation's Mobile Workforce Management system which links computers in over 600 field trucks across the province. The system

Reduction in customer costs through Power Smart: $112.9 million

Serving customers

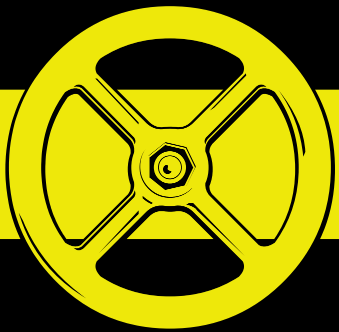
enables dispatch offices in Brandon, Selkirk and Winnipeg along with customer service centres to wirelessly assign field staff based on location, driving times, work priority and skills required. This centralized work planning combined with the relocation of staff and equipment in regional centres will strengthen electrical outage response and enhance system maintenance.

Responding to service disruptions

Electricity and natural gas service are critical parts of modern life; however disruptions in that service are an unfortunate reality of the energy utility business. As part of an effort to maintain the safety of all people as well as limit the damage to Manitoba Hydro and customer assets, the corporation has a comprehensive emergency response program to ensure an effective and coordinated response to possible emergencies and disasters. That program includes business continuity planning and continuous improvement.

On June 25, Manitoba Hydro staff responded to power outages affecting approximately 7 000 customers after heavy rains, lightning and high winds pounded the southwestern corner of the province. Over 12 centimetres of rain and winds exceeding 80 kilometres per hour resulted in 13 broken distribution poles, 30 leaning poles, 16 damaged transformers and 111 breaks in conductors. Employees from across the corporation responded and were able to restore power to virtually all customers within 12 hours. Less than three weeks later high winds and intense lightning again hit the southwestern corner causing outages to over 1 500 customers. Staff once again rose to the challenge working through the night to restore power to almost all customers by the next day. Repairs required included replacing 19 poles, installing six new transformers and 44 insulators, reinstalling 10 spans of three-phase conductor and repairing 131 conductor breaks.

In January, a breach in a TransCanada Corporation natural gas pipeline near Otterburne disrupted supply to Manitoba Hydro's system in south central Manitoba leaving about 3 600 customers without gas service. Facing a multiple day outage with temperatures dipping below -40 degrees Celsius, the corporation worked closely with the Provincial Emergency Measures Organization to identify critical community sites, such as hospitals, personal care homes and public warming centres, and then with TransCanada to source a temporary supply of compressed natural gas that was trucked in from Saskatchewan to service those sites. Once TransCanada repaired their pipeline, Manitoba Hydro staff went door-to-door, visiting all affected customers to ensure natural gas service was safely restored and to assist with relighting appliances. Service to all customers was restored within four days of the initial disruption. Throughout the outage, Manitoba Hydro worked closely with TransCanada to keep customers as well as municipal and provincial officials informed, providing regular media updates and important safety information.



Volume of natural gas delivered:

2 280 million cubic metres

Working with Boeing Canada staff, Manitoba Hydro helped make energy efficiency improvements to the compressed air system at Boeing's plant in Winnipeg.

Promoting safety

Maintaining a safe workplace and encouraging public safety around our facilities are critical components of all Manitoba Hydro activities.

Accident Frequency Rate:
Incidents per 200 000 hours worked
Target: < 0.6

0.7

Accident Severity Rate:
Calendar days lost per 200 000 hours worked
Target: < 12.0 days

11.1

High Risk Incidents:
Target: 0

0

Tailboard meetings are held prior to all site or field work to review job plans and ensure all safety hazards are identified, discussed and understood.

Promoting safety

Creating a culture of safety

Manitoba Hydro's workplace safety performance, as measured by two key indicators, was among the best in the last decade. In 2013-14, the corporation achieved an accident frequency rate of 0.69 incidents per 200 000 hours worked and an accident severity rate of 11.07 calendar days lost due to workplace injury or illness per 200 000 hours worked.

A number of initiatives were introduced during the fiscal year as part of an ongoing effort to instill a culture of safety among employees. In October, 16 Life Saving Rules were introduced to set a new basic standard for employee safety at Manitoba Hydro. Examples of these simple rules include: all workers must be qualified and authorized to perform work at Manitoba Hydro; obtain excavation authorization and use shoring as required; and, use personal protective equipment as required. The concepts inherent in the Life Saving Rules are to be incorporated into safe work procedures and all work activities within the areas of design, material specification, purchasing, contract administration, construction, operation and maintenance.

The corporation also adopted a new, non-subjective safety performance measure that will track the number of serious incidents opposed to high risk incidents beginning in 2014-15. These serious incidents will be communicated through safety incident alerts to managers, field safety officers, bargaining units and all employees in the business unit where the incident occurred or for whom the incident has direct relevance. The intent of these timely alerts is to reduce accidents by drawing attention to the incidents and reinforcing safe work practices.

A year-long internal safety awareness campaign kicked off in January featuring 12 employees who consistently display a personal commitment to safety in their work responsibilities and performance. These safety ambassadors and their personal reasons for staying safe at work and home are profiled throughout the year in the corporation's internal newsletter, on monthly posters displayed at various work locations and through quarterly videos. This is the third year for the safety campaign.

Manitoba Hydro's internal safety awareness campaign profiles employees who consistently display a personal commitment to safety.

Promoting public safety

Safety and educational resources from Manitoba Hydro including presentations, in-services, videos and educational kits continue to be in high-demand by schools throughout the province. For example, the corporation provides resources instructing students and drivers on what to do if a school bus makes contact with a downed power line. Brochures were distributed to 21 870 students who rode a bus to school as were another 1 100 copies of pamphlets specifically targeted at bus drivers. Video segments on school bus safety and safe exit from a vehicle were also viewed at 68 schools. In total, presentations promoting safety around natural gas and electricity were delivered to over 10 000 students in 2013-14.

An educational iPad app developed by Manitoba Hydro to help teach children about electrical safety had more than 3 000 downloads in the past fiscal year. Electric Gremlins takes the player on a race through a maze of wires to find and fix electrical hazards. Available free-of-charge on iTunes, the app is promoted through schools province-wide. Versions for iPhones and iPods as well as Android devices are in the final stages of development.

Protecting the environment

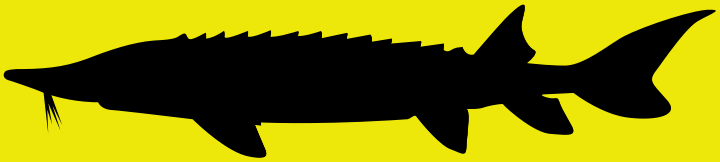
Manitoba Hydro strives to uphold the principles of sustainable development, incorporating environmental awareness and protection in everything we do.

Amount of generation from renewable sources:

99.6%

Number of sturgeon stocked in the Nelson River since 1994:

173 400



Total annual greenhouse gas emissions in 2013:

163 kilotonnes CO_2 equivalent

Annual target (6% below 1990 levels):

520 kilotonnes

A Nelson River Sturgeon Board employee returns a sturgeon to the Nelson River after collecting data about its weight, length and age. The Nelson River Sturgeon Board is funded, in part, by Manitoba Hydro and the Province of Manitoba.

Protecting the environment

Assessing Keeyask sustainability

The results from an independent assessment of the planned 695-megawatt Keeyask Generating Station under the Hydropower Sustainability Assessment Protocol were released in September. The report concluded 95 percent of the assessment aspects ranked above the good practice level. The project received the highest possible score on 16 of the 22 topics assessed, more than any other project assessed in the world to date.

The Hydropower Sustainability Assessment Protocol is a framework to assess hydropower projects according to a defined set of sustainability topics encompassing environmental, social, technical and financial issues using a consistent and globally applicable methodology. The protocol was developed by the Hydropower Sustainability Assessment Forum which included representatives from the hydropower sector as represented by the International Hydropower Association, social and environmental non-governmental organizations including the Nature Conservancy, World Wildlife Fund, Transparency International and Oxfam, governments in developed and developing countries, and financial organizations such as the World Bank and the Equator Banks.

Analyzing greenhouse gas emissions

A lifecycle analysis of the proposed Conawapa Generating Station by the Pembina Institute found the associated greenhouse gas emissions would be very small and lower than any of the generation alternatives. The results mirror those of previous analysis done for the Keeyask Generating Station and the Wuskwatim Generating Station. One component of the analysis is the implications associated with flooding. While greenhouse gases are produced and exchanged naturally by terrestrial and aquatic ecosystems, reservoirs may increase emissions of carbon dioxide and methane, primarily in the first decade following reservoir creation.

Monitoring at the Wuskwatim Generating Station in the first two years following creation of its reservoir indicated greenhouse gas concentrations were in the same range as pre-project levels. These results were consistent with Manitoba Hydro's expectation that the very small amount of flooding at Wuskwatim, less than one-half of one square kilometre, would have a minimal impact on greenhouse gas production.

Rehabilitating Wuskwatim site

Work continued in the fiscal year to rehabilitate areas disturbed by the construction of the Wuskwatim Generating Station and not required for long-term operation. Approximately 550 hectares of land, including borrow pits and contractor

Named one of Canada's Greenest Employers: 2012, 2013, 2014 work areas, were shaped and graded, permanent erosion control works were established and cleared areas were re-vegetated with native species. Approximately 77 hectares of land have been seeded with native grass species and about 280 000 jack pine, black spruce and white spruce seedlings have been planted to the end of the fiscal year. Tree seedlings will be monitored over the next few years to assess growth and confirm survival.

A commitment to site rehabilitation by the Wuskwatim Power Limited Partnership – a partnership between Manitoba Hydro and the Nisichawayasihk Cree Nation – was set out in the Wuskwatim Generating Station's environmental impact statement.

Codifying agricultural bio-security

A new policy further ensures Manitoba Hydro's construction and maintenance activities on agricultural land do not contribute to the spread of disease, pests and invasive plant species. Developed in consultation with government agencies and industry, the new Agricultural Bio-security Policy formalized long-standing practices and created standard operating procedures that assess the potential bio-security risk, considering factors such as soil conditions and time of year, and prescribes actions to manage the risks. All Manitoba Hydro employees and contractors working on private agricultural land are required to follow these operating procedures.

Tree planting is part of the rehabilitation plan to restore areas affected by construction of the Wuskwatim Generating Station.

Protecting the environment

Collaborating on lake sturgeon

In December, Manitoba Hydro and the government of Manitoba signed a memorandum of understanding that recognized a common interest in the preservation and enhancement of lake sturgeon stocks. The memorandum established an implementation committee to undertake collaborative monitoring and research activities that will increase the knowledge of lake sturgeon in Manitoba. The committee will prepare an annual work plan to guide activities and will prepare a brief annual report highlighting the activities undertaken through the memorandum of understanding.

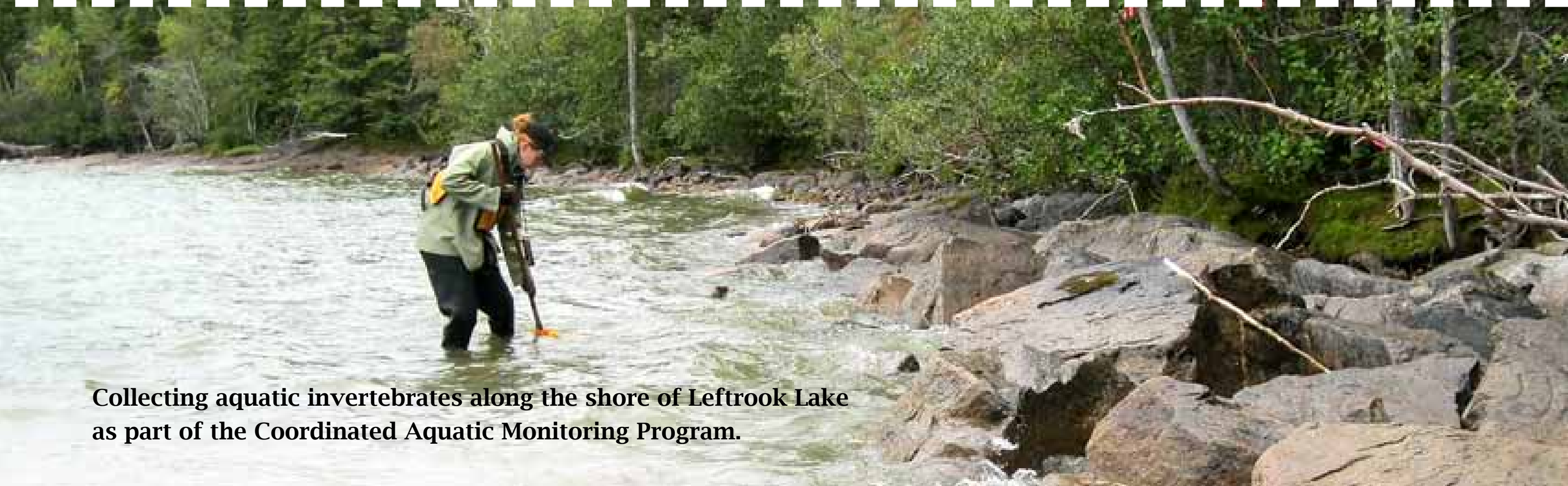
Manitoba Hydro is also providing up to $50 000 annually over five years under its Lake Sturgeon Stewardship and Enhancement Program for cooperative research projects to increase the body of scientific knowledge regarding the life stages of the species. The memorandum has a five-year term with provisions for extension upon mutual agreement.

Describing aquatic health

The Coordinated Aquatic Monitoring Program (CAMP) completed its first three-year monitoring report, based on data collected from 2008 to 2010. The report will be available on the program's new website at www.campmb.com. Manitoba Hydro, in cooperation with the Province of Manitoba, initiated CAMP in 2008 to monitor the aquatic health of water bodies affected by hydroelectric development. Working with experts from the International Institute of Sustainable Development, Fisheries and Oceans Canada and the University of Manitoba, the program is developing indicators for hydrology, water quality, aquatic insects and fish. These indicators will be used to describe the state of aquatic ecosystem health and for reporting to regulatory authorities, stakeholders and the general public.

Preparing for zebra mussels

A zebra mussel monitoring program on the Winnipeg and Red rivers was expanded to include the Jenpeg Generating Station, located on the Nelson River approximately 100 kilometres downstream of Lake Winnipeg. In October, the Province of Manitoba confirmed the presence of zebra mussels in Lake Winnipeg, the first such infestation in Manitoba. An invasive species that multiplies quickly, zebra mussels are one of the only freshwater mollusk that can firmly attach themselves to solid objects. As a result, they can clog intake structures at hydroelectric and thermal generating stations as well as hydraulic control structures. The corporation also initiated a study to review zebra mussel control methods used at stations operated by other North American utilities, identify systems or structures at risk of infestation and identify suitable zebra mussel control techniques.



Collecting aquatic invertebrates along the shore of Leftrook Lake as part of the Coordinated Aquatic Monitoring Program.

Supporting environmental awareness

Work began on a new interactive exhibit at the Manitoba Electrical Museum that explains Manitoba Hydro's environmental assessment activities and approach to environmental issues. Aimed at grade six students, the exhibit includes short videos featuring some of the science that the corporation undertakes before, during and after construction of major projects; highlights ecosystem health and key species such as caribou and sturgeon; and incorporates visual, audio and tactile components to engage learners. The exhibit is scheduled to be open to the public in the summer of 2014.

Manitoba Hydro's Environmental Partnership Fund provided funding or in-kind support to 20 local non-profit organizations in 2013. Established in 1993, the fund provides one time or multi-year contributions to support the development and implementation of environmental education projects with a sustainable development focus. One project receiving support in 2013 was the development of the Lake Friendly, What is Your H20 IQ, educational resource. Designed to provide educators with user-friendly locally relevant information and resources, the workbook explores issues related to water and the Lake Winnipeg watershed.

The Forest Enhancement Program provided funding to 62 projects in 2013 to enhance community forests and support forest education. One of those projects was the planting of 36 fruit trees in the South Osborne Community Orchard, Winnipeg's largest community garden. The orchard will grow fruit, up to 4 500 kilograms in a good harvest year, add diversity to the urban forest and provide a site for educational field trips. Since 1995, over 117 000 trees have been planted as a result of the Forest Enhancement Program.

Checking for zebra mussels at the Seven Sisters Generating Station on the Winnipeg River.

Building relationships

Manitoba Hydro strives to build productive relationships with employees, suppliers and other stakeholders who are integral to our ongoing success.

Contracts awarded to Manitoba companies:

$675 million

Contracts awarded to Aboriginal Manitoba companies:

$288 million

Members of the Walking Wolf Dance Troupe perform at Manitoba Hydro Place as part of the corporation's Aboriginal Awareness Week celebrations.

Building relationships

Building a diverse workforce

Manitoba Hydro continued to work to attract, develop and retain a skilled workforce that reflects the diversity of the province. Those efforts were recognized by the editors of Canada's Top 100 Employers for 2014. Manitoba Hydro was named to their list for the fourth consecutive year and was also identified as one of Canada's Best Diversity Employers.

Manitoba Hydro's Northern and Southern Aboriginal Pre-placement Training programs and the Aboriginal Line Trades Training Program hired a combined 27 new trainees in the fiscal year. These pre-placement programs provide on-the-job training, academic upgrading and mentorship to help Aboriginal candidates acquire skills needed to successfully move into Manitoba Hydro's technical trades training programs. Twenty-three previously hired candidates successfully completed their pre-placement training in the past year and were selected for the power electrician, operating technician or line trades training programs.

Working with the University of Manitoba's Internationally Educated Engineers Qualification Program, Manitoba Hydro continued to support engineers who have trained abroad and want to fulfill the academic requirements of the Association of Professional Engineers and Geoscientists of Manitoba. Two graduates of the university's program were hired permanently into the corporation's Internationally Educated Engineer-in-Training Program. One previous cooperative work term student and subsequent graduate of the program was also hired into a permanent professional engineering position. Since 2004, Manitoba Hydro has awarded two bursaries a year, worth $1 500 each, to students enrolled in the program and provided cooperative work terms.

Strengthening Aboriginal connections

Manitoba Hydro continued to foster business relationships with Aboriginal companies, address the effects of its operations on Aboriginal communities and undertake activities intended to create an appreciation of Aboriginal culture in the workplace.

Using procurement strategies and policies, Manitoba Hydro created business opportunities for Aboriginal enterprises. These strategies included restricted tendering or creation of smaller custom work packages to suit the business capacities of a community in proximity of the work. Of the $675 million in contracts awarded to Manitoba companies in the 2013-14 fiscal year, $288 million was awarded to Manitoba Aboriginal companies.

In September, individual offers of settlement were made to commercial trappers from Moose Lake. The settlements address past, present and future commercial income loss arising from the development of the Grand Rapids Generating Station.

Percentage of employees who are women: 24.5%

Percentage of employees who are Aboriginal: 17.6%

Percentage of employees with disabilities: 9.9%

Percentage of employees who are visible minorities: 7.8%

Manitoba Hydro's Boat Patrol Program, Debris Management Program and Safe Ice Trails Program played integral roles in improving, mitigating and compensating for adverse impacts and providing for safe navigation on waterways affected by hydroelectric development.

The Boat Patrol Program employed about 35 seasonal Aboriginal workers from communities in northern Manitoba for 19 boat patrol crews. These crews mapped and recorded daily routes, marked deadheads and reefs, identified debris work areas, placed hazard markers and gathered floating debris. The Debris Management Program implemented about a dozen community-based contracts for identifying debris work locations on shore and collecting then burning the debris. Under the Safe Ice Trails Program seasonal contract workers, typically resource users hired from Northern Aboriginal Communities, created approximately 2 000 kilometres of ice trails. The trails were then monitored by local Manitoba Hydro employees who mapped trails, tested ice thickness, cleared obstructions and routinely monitored and patrolled to provide safe alternatives to traveling on unchecked routes.

Ongoing promotion of Aboriginal cultural awareness among employees included celebrating National Aboriginal Awareness Week for the eighth consecutive year. Activities between May 22 and 24 included a lunch-time presentation by Commissioner James Wilson of the Treaty Relations Commission of Manitoba; a performance by the Walking Wolf Dance Troupe; and an Aboriginal crafters marketplace at Manitoba Hydro Place that featured a musical performance by employees and teepee teachings by an Aboriginal elder. The corporation also offered Aboriginal Cultural Awareness workshops for employees. Over 110 workshops have been held since 2005 with nearly 2 000 employees participating.

Contributing to communities

Manitoba Hydro continued to work with Project Search, a unique business-partnered transition program for high school students with an intellectual disability. The 10-month program is unique in that students are fully embedded in a business workplace for the duration of their last year of high school. Students started and ended their day in a classroom at Manitoba Hydro Place where they learned employability skills. Between classes, students learned job skills while participating in a variety of work experience assignments. The program is targeted at students whose main goal is employment and who will benefit from career exploration. In June, seven students graduated from the program and from high school.

In 2013, Manitoba Hydro continued to be Canadian Blood Services' largest partner in the province. Employees donated over 1 000 units of blood for the second year in a row, including 133 donations in December

Building relationships

alone – the most donations from a Manitoba organization in one month for all of 2013.

Over 1 200 athletes competed in the Manitoba Hydro Power Smart Winter Games over six days in March. Morden, Winkler and the Rural Municipality of Stanley hosted the athletes who competed in 13 different sports. Manitoba Hydro has sponsored the games since 2002 and been title sponsor since 2006.

In September, Manitoba Hydro representatives participated in the official opening of a 40-kilometre addition to the TransCanada Trail at the Seven Sisters Generating Station on the Winnipeg River. Manitoba Hydro supported the project by allowing the trail to cross over the generating station and dikes as it winds its way between Old Pinawa Dam Provincial Park and Whiteshell Provincial Park.

Other community events supported in 2013-14 included the Power Smart Santa Claus Parade in Winnipeg, the Aurora Winter Fest in Churchill and the Winnipeg Symphony Orchestra's Power Smart Holiday tour which took the symphony to Steinbach, Winkler, Portage la Prairie and the Baker Hutterite Colony near MacGregor.

Helping a neighbour

When one of the worst ice storms in decades hit southern Ontario in December knocking out power to over 300 000 Toronto Hydro customers, Manitoba Hydro was quick to extend an offer of assistance. Within hours of Toronto Hydro accepting, there was a plane load of Manitoba Hydro volunteers ready to go. On Christmas Eve morning, 42 employees flew to Toronto where they worked 12-hour shifts in severe conditions, helping to maintain an around-the-clock response to the storm damage. Toronto Hydro was very appreciative and praised the Manitoba Hydro employees for their work ethic, safety focus and ability to deal with challenging circumstances. All employees returned to Winnipeg on December 31.

Students from St. Laurent School build a bottle opener out of nuts and bolts as part of a Manitoba Hydro recruitment event in the community.

Manitoba Hydro staff return home after helping Toronto recover from a devastating ice storm over the Christmas holiday. Photo by John Woods, Winnipeg Free Press.

Corporate governance

The affairs of Manitoba Hydro are overseen by a board whose members are appointed by the Lieutenant Governor in Council of Manitoba.

The board's primary responsibility is to ensure that the corporation carries out its legislative mandate. The board considers the principles of sustainable development, and Manitoba Hydro's code of ethics, in its decisions. Minutes of board meetings are public, and the corporation's annual report and quarterly financial statements are tabled in the legislature. The annual report is approved by a committee of the Manitoba Legislature. The mandate of the corporation is reviewed by The Crown Corporations Council.

The Audit Committee of the board reviews Manitoba Hydro's integrated financial forecast, and makes recommendations to the board. The Audit Committee reviews whether Manitoba Hydro's quarterly and annual financial statements present fairly the financial position and performance in accordance with generally accepted accounting principles. The Audit Committee confirms whether management has assessed areas of potential significant financial and operational risk and has taken appropriate measures, and the Audit Committee reviews management's systems for ensuring legal compliance. The Audit Committee obtains opinions from external auditors, internal auditors, and management on the quality of internal controls, and verifies that external auditors have performed their duties with sufficient independence from management.

The Human Resources and Governance Committee assists the board with succession planning and human resources issues. The Committee reviews the board's approach to corporate governance with a view to best practices and Manitoba Hydro's mandate.

All of the members of the board sit on the Planning Committee, which approves the corporate strategic plan.

Integrity Program

Manitoba Hydro encourages employees and others to speak up on matters of concern without fear of reprisal, through its Integrity Program. All disclosures under the Integrity Program are protected by strict rules of confidentiality.

Below is a summary of all disclosures received during 2013-14 which allege wrongdoing as defined in The Public Interest Disclosure (Whistleblower Protection) Act:

Total number of disclosures received:	2
Number of disclosures ongoing from 2012-13:	10
Number of disclosures acted upon:	12
Number of disclosures not acted upon:	0
Number of investigations commenced/continued:	12
Number of disclosures that were verified:	3
Number of disclosures that were not verified:	5
Number of disclosures carried forward to 2014-15:	4

Corrective action was taken for each verified incident, as follows:

- Funds were recovered from a service agent for not acting in the corporation's best interests and the contract was terminated.
- An employee received a written warning for abusive comments to a female fellow worker, and counseling was provided to the entire department.
- Two employees each received a five-day suspension and one of them was temporarily demoted for engaging in private work in conflict with their company work.

Manitoba Hydro-Electric Board

Appearing left to right:

Carmen Neufeld
Tina Keeper
Michael Spence
Dr. John Loxley
Eugene Kostyra
William C. Fraser, FCA, Chair
David Crate
Dudley Thompson
James Husiak, CA
Larry Vickar
Not in photo: Frank Whitehead

Manitoba Hydro Senior Officers

Appearing left to right:

Bruce Barrett, P. Eng
Vice-President, Major Capital Projects

Lloyd Kuczek, P. Eng, MBA
Vice-President, Customer Care & Energy Conservation

Bryan Luce
Vice-President, Human Resources and Corporate Services

Ken M. Tennenhouse, LL.B
Vice-President, General Counsel and Corporate Secretary

E. Ruth Kristjanson, BA (Hons), MA
Vice-President, Corporate Relations

Scott A. Thomson, CA
President and Chief Executive Officer

G. Brent Reed
Vice-President, Customer Service and Distribution

Lorne Midford, P. Eng
Vice-President, Generation Operations

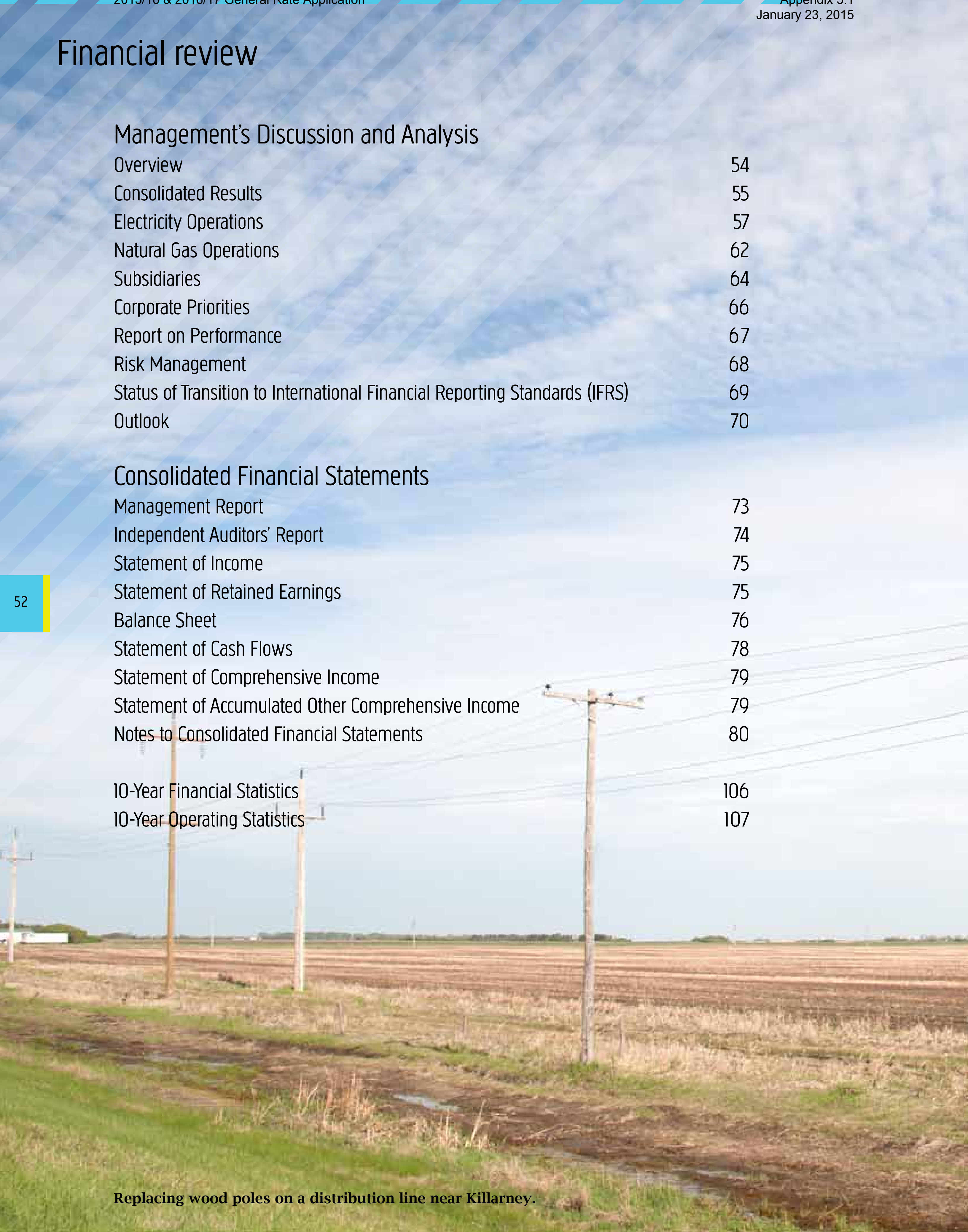
Shane Mailey, P. Eng
Vice-President, Transmission

Darren B. Rainkie, CA, CBV
Vice-President, Finance and Regulatory

Financial review

Management's Discussion and Analysis

Consolidated Financial Statements



Replacing wood poles on a distribution line near Killarney.

The Management's Discussion and Analysis (MD&A) section of the Annual Report provides comments on the financial results and operational performance of Manitoba Hydro for the year ended March 31, 2014 with comparative information where applicable. The MD&A also provides an assessment of Corporate risks and contains forward-looking statements regarding conditions and events which may affect financial performance in the future. Such forward-looking statements are subject to a number of uncertainties which are likely to cause actual results to differ from those anticipated. For context, the MD&A should be read in conjunction with the consolidated financial statements and notes.

As a provincially-owned Crown Corporation, Manitoba Hydro's mandate is to provide for the continuance of a supply of energy to meet the needs of Manitoba consumers in the most reliable, economic, and environmentally sustainable manner. In fulfilling its mandate, Manitoba Hydro has assessed all known risks and has established a number of priorities with related measures and targets. In addition to a review of financial and operational performance, the MD&A also reviews Manitoba Hydro's progress towards achieving its strategic priorities.

OVERVIEW

Manitoba Hydro's consolidated net income from electricity and natural gas operations for the fiscal year ended March 31, 2014 was $174 million compared to $92 million in the previous fiscal year. The increase in net income of $82 million was largely attributable to increased revenues from domestic and extraprovincial electricity sales partially offset by higher expenses.

Consolidated net income for the 2014 fiscal year was comprised of net income of $154 million in the electricity sector and net income of $20 million in the natural gas sector. The gas sector net income represented a $12 million improvement over the previous year which was mainly a result of colder weather during the winter of 2013-14 compared to the winter of 2012-13.

Consolidated net income for 2013-14 was higher than the forecasted net income of $136 million largely due to higher than forecast electricity and gas revenues partially offset by higher than forecast power purchases.

Net income of $174 million contributed to the corporation's retained earnings of $2 716 million at March 31, 2014, the highest level of equity in the corporation's history. The interest coverage and capital coverage ratios exceeded the target level while the debt to equity ratio was close to the target level for the year.

CONSOLIDATED RESULTS

The following schedule summarizes Manitoba Hydro's consolidated financial results for the fiscal year ended March 31, 2014 compared to the previous fiscal year:

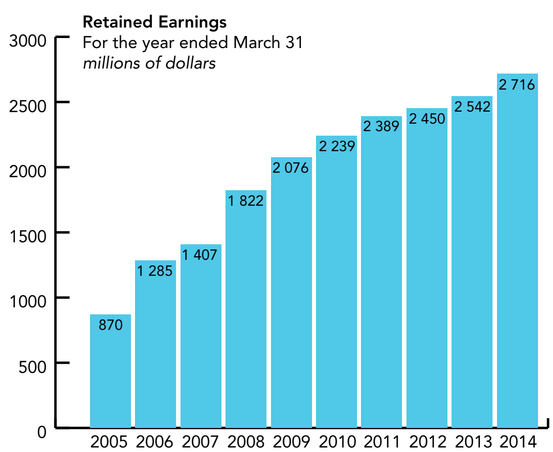
	Electricity		Natural Gas		Consolidated		Change
	2014	2013	2014	2013	2014	2013	
	millions of dollars						
Revenues							
Manitoba (net of cost of gas sold)	1 475	1 410	163	147	1 638	1 557	81
Extraprovincial	439	353	-	-	439	353	86
	1 914	1 763	163	147	2 077	1 910	167
Expenses	1 782	1 692	143	139	1 925	1 831	94
Net income before non-controlling interest	132	71	20	8	152	79	73
Net loss attributable to non-controlling interest	22	13	-	-	22	13	9
Net income	154	84	20	8	174	92	82
Total assets	14 950	13 928	689	614	15 639	14 542	1 097
Retained earnings	2 654	2 500	62	42	2 716	2 542	174
Financial Ratios							
Debt:Equity					76:24	75:25	
Interest coverage					1.28	1.15	
Capital coverage					1.35	1.25	

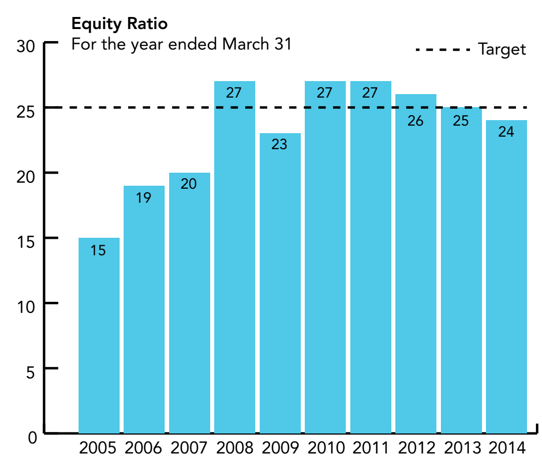
Revenues from consolidated electricity and natural gas operations totaled $2 329 million in 2013-14 compared to $2 092 million in the previous fiscal year. After deducting the cost of gas sold, which is a pass-through cost with no mark-up to customers by Manitoba Hydro, revenues amounted to $2 077 million compared to $1 910 million in the prior year. The $167 million or 8.7% increase in revenues was largely attributable to increased extraprovincial electricity sales due to favourable water conditions and higher export prices, increased domestic electricity sales due to colder weather than the previous year and electricity rate increases.

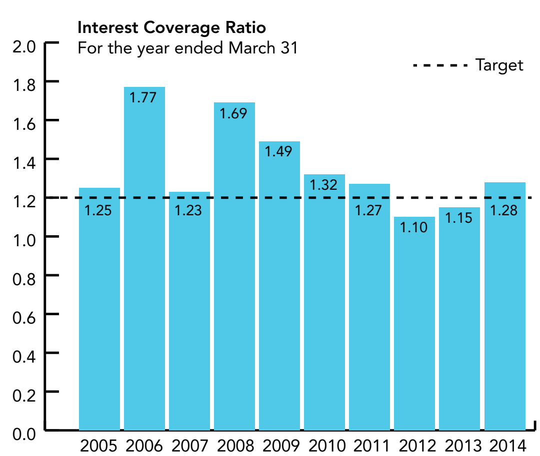
Expenses for electricity and natural gas operations totaled $1 925 million in 2013-14, an increase of $94 million or 5.1% over the previous year. The increase was largely due to a $44 million increase in fuel and power purchased, a $24 million increase in operating and administrative expense and a $19 million increase in depreciation and amortization.

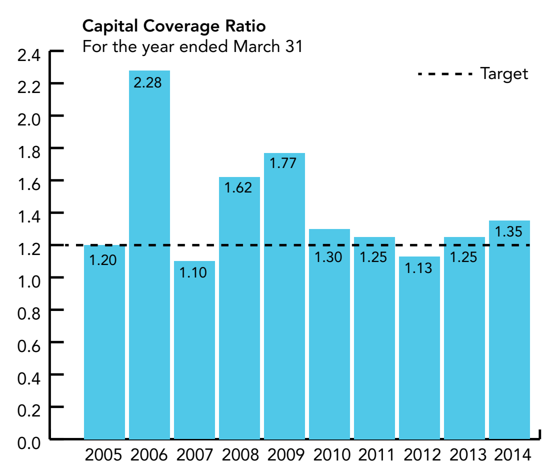
Net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's (TPC) 33% share of the Wuskwatim Power Limited Partnership's (WPLP) operating results for 2013-14. The WPLP has two limited partners, Manitoba Hydro and TPC which is owned beneficially by Nisichawayasihk Cree Nation (NCN) and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro.

Net income from electricity and natural gas operations amounted to $174 million in 2013-14 compared to $92 million in the previous year. The consolidated net income increased retained earnings to $2 716 million at March 31, 2014. As indicated in the accompanying chart, net income of $174 million resulted in the equity ratio being 24% at March 31, 2014, slightly lower than the corporation's target of 25%. The capital coverage ratio of 1.35 exceeded the target of 1.20 and the interest coverage ratio of 1.28 exceeded the target of 1.20.









Financing

Cash provided from operations in 2013-14 was $690 million, an increase of $101 million from the previous year. The increase reflects higher domestic and extraprovincial sales than the previous year.

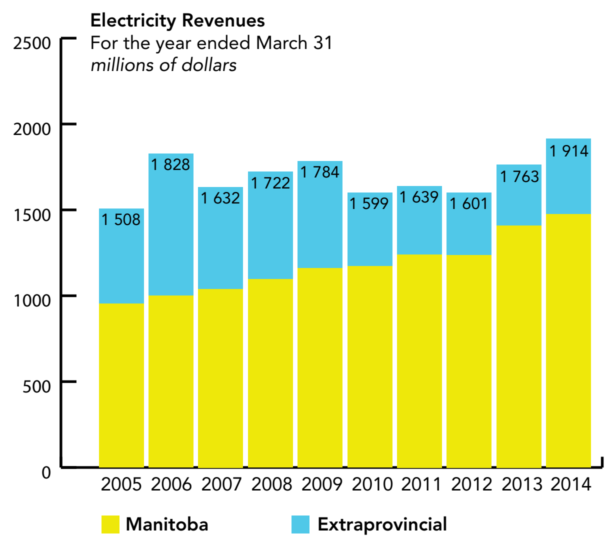
Proceeds from financing arranged by the corporation amounted to $1 320 million in 2013-14 compared to $807 million in the previous year. Current year proceeds were used to fund new capital requirements and to retire long-term debt maturing during the year.

During 2013-14, the corporation retired $613 million of debt comprised of Provincial Advances of $575 million, HydroBonds of $14 million and Manitoba Hydro-Electric Board Bonds of $24 million.

ELECTRICITY OPERATIONS

Electricity Revenues

Electricity revenues totaled $1 914 million, an increase of $151 million or 8.6% from the previous year. The increase was the result of increases of $86 million in extraprovincial revenues and $65 million in domestic revenues. The increase in extraprovincial revenues was primarily due to increases in export volumes resulting from higher generation from stations on the Lower Nelson River due to higher flows than prior year and higher export prices. The increase in domestic revenues was primarily due to higher consumption as a result of one of the coldest winters on record in Manitoba and rate increases.



The breakdown of electricity revenues by customer segment is as follows:

Electricity Revenues and kWh Sales

For the year ended March 31

	2014	2013	% change	2014	2013	% change
	millions of dollars			*millions of kWh*		
Manitoba						
Residential	606	554	9.4	7 889	7 334	7.6
General service	497	465	6.9	7 269	6 877	5.7
Industrial	302	299	1.0	7 199	7 266	(0.9)
Other revenue	70	69	1.4	-	-	-
	1 475	1 387	6.3	22 357	21 477	4.1
1% rate deferral	-	23	-	-	-	-
Manitoba revenue	1 475	1 410	4.6	22 357	21 477	4.1
Extraprovincial	439	353	24.4	10 537	9 087	16.0
	1 914	1 763	8.6	32 894	30 564	7.6

Revenues from electricity sales in Manitoba totaled $1 475 million in 2013-14, an increase of $65 million from the previous year. Electricity consumption in Manitoba was 22 357 million kilowatt-hours, 880 million kilowatt-hours higher than the previous year. The increase in consumption was mainly due to higher heating loads as a result of colder winter weather in 2013-14 and customer growth.

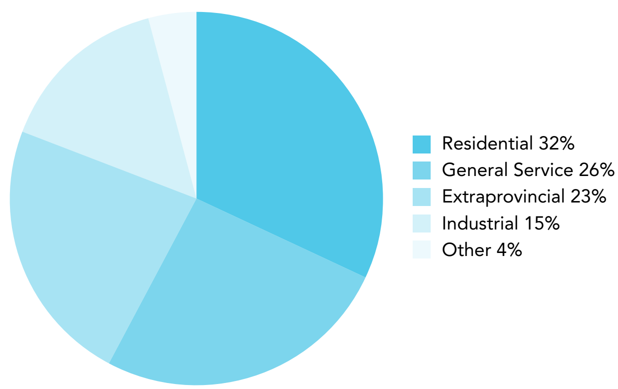
Revenues from sales to residential customers for 2013-14 amounted to $606 million, an increase of $52 million or 9.4% from the previous year. The increase was primarily a result of a higher heating load from colder winter weather, rate increases implemented during the year and increases in the number of residential customers of 6 400 to 486 654, an increase of 1.3% compared to the previous year.

Revenues from general service customers amounted to $497 million in 2013-14, an increase of $32 million or 6.9% from the previous year. The increase was mainly attributable to the rate increases implemented during the year, colder winter weather and an increase of 577 customers.

Revenues from large industrial customers amounted to $302 million, an increase of 1.0% or $3 million from the previous year. The increase was mainly the result of rate increases implemented during the year and an increase of customers partially offset by decreased consumption.

Extraprovincial revenues totaled $439 million in 2013-14, an increase of $86 million from the previous year. The increase reflects higher U.S. sales volumes resulting from higher generation from stations on the Lower Nelson River due to higher flows than prior year and higher export prices partially resulting from favorable foreign exchange rates on U.S. sales. Of the total extraprovincial revenues, $392 million or 89% was derived from the U.S. market, while $47 million or 11% was from sales to Canadian markets.

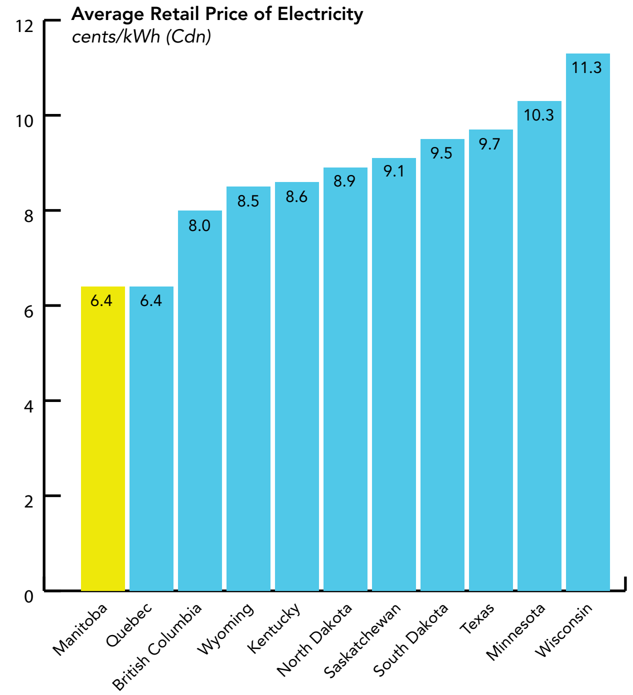
Electricity Revenues
For the year ended March 31, 2014



Electricity Rates

The Public Utilities Board (PUB) issued Order 43/13 on April 26, 2013, which approved a 3.5% increase in electricity rates effective May 1, 2013. The PUB directed that 2.0% of the 3.5% increase be included in general revenues and that 1.5% of the approved rate increase be set aside to be utilized to mitigate rate increases when Bipole III is placed in-service. During the 2013-14 fiscal year $19 million was set aside for this purpose.

Manitoba Hydro's domestic electricity rates continue to be among the lowest overall in North America. This is illustrated in the accompanying chart which was excerpted from utilities' annual reports and United States Department of Energy and Edison Electric Institute publications.



Electricity Expenses

Electricity expenses totaled $1 782 million for 2013-14, an increase of $90 million or 5.3% over the previous year. The increase in expenses was the result of a $44 million increase in power purchased, a $21 million increase in operating and administrative, an $18 million increase in depreciation and amortization, a $10 million increase in capital and other taxes, a $7 million increase in water rentals and assessments and a $6 million increase in other expenses, partially offset by a $16 million decrease in finance expense.

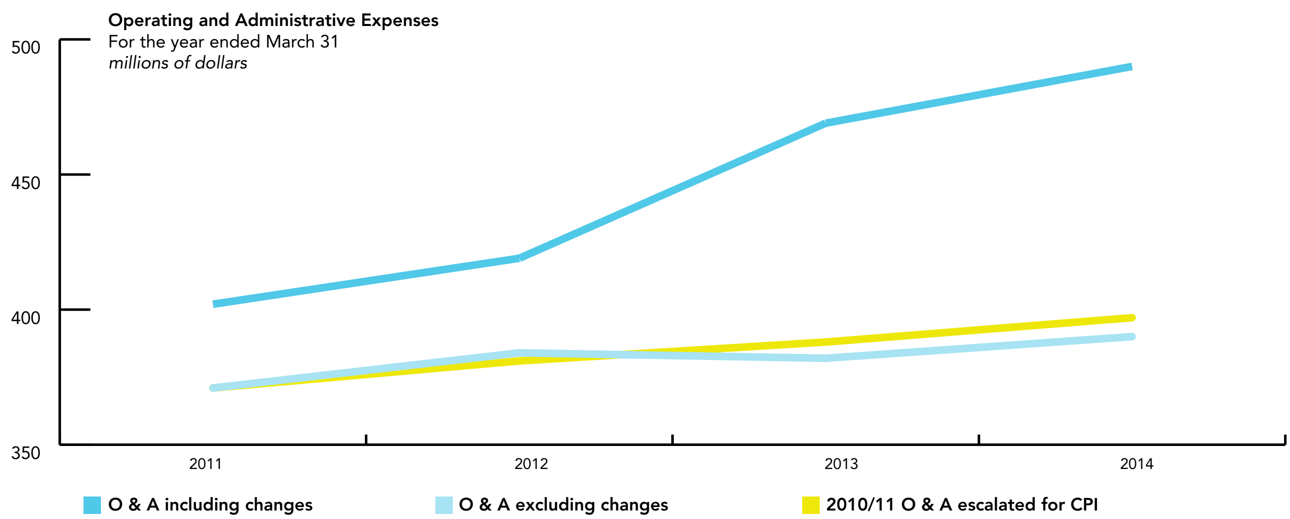
Electricity Expenses

For the year ended March 31

	2014	2013	% change
	millions of dollars		
Operating and administrative	490	469	4.5
Finance expense	436	452	(3.5)
Depreciation and amortization	412	394	4.6
Water rentals and assessments	125	118	5.9
Fuel and power purchased	177	133	33.1
Capital and other taxes	97	87	11.5
Other expenses	36	30	20.0
Corporate allocation	9	9	-
	1 782	1 692	5.3

Operating and administrative expenses are comprised primarily of labour, material and overhead costs associated with operating, maintaining and administering the facilities and programs of the corporation. In 2013-14, operating and administrative expenses for electric operations amounted to $490 million, an increase of $21 million over 2012-13. The increase in operating and administrative expenses was primarily due to higher pension and other benefit costs of $13 million related to changes in discount and mortality rates and greater employer contribution requirements. After adjusting for these changes, the increase in operating and administrative expenses for 2013-14 was $8 million or 1.7% as compared to the previous year.

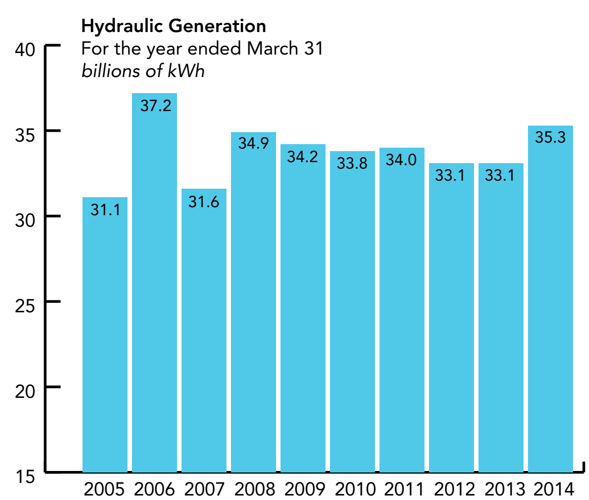
The following graph provides a comparison of the growth in operating and administrative expenses, including and excluding accounting changes as well as changes in the pension and benefit costs, as compared to changes in the consumer price index (CPI).



Finance expense totaled $436 million in 2013-14, a decrease of $16 million or 3.5% from the previous year. The decrease was primarily due to lower interest rates, higher realized foreign exchange gains on U.S. debt and higher recognized gains on the sale of U.S. sinking fund investments. This was partially offset by higher volumes of long-term debt to finance capital expenditures and a weaker Canadian dollar.

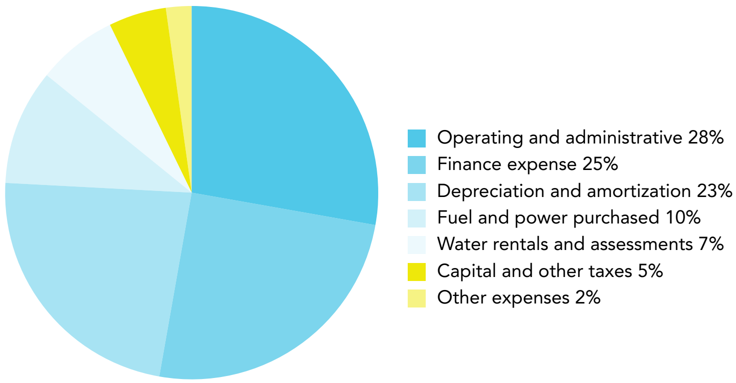
Depreciation and amortization expense amounted to $412 million in 2013-14, an increase of $18 million or 4.6% from the previous year. The increase was mainly attributable to new additions to plant and equipment coming into service, including the Wuskwatim Generating Station which was fully in-service during the 2013-14 fiscal year.

Water rentals and assessments amounted to $125 million in 2013-14, an increase of $7 million from the previous year. The increase reflects greater hydraulic generation due to higher water flows in 2014 compared to the prior year. Hydraulic generation amounted to 35.3 billion kilowatt-hours in 2013-14 compared to 33.1 billion kilowatt-hours in 2012-13.



Fuel and power purchased includes fuel for the thermal generating stations and remote diesel sites, purchases of wind power from the independently-owned St. Leon and St. Joseph wind farms and from electricity imports. Fuel and power purchased was $177 million in 2013-14, an increase of $44 million or 33.1% over 2012-13. The increase in power purchased was primarily the result of higher purchased volumes due to colder weather and higher system merchant purchases due to increased arbitrage opportunities between markets.

Electricity Expenses
For the year ended March 31, 2014



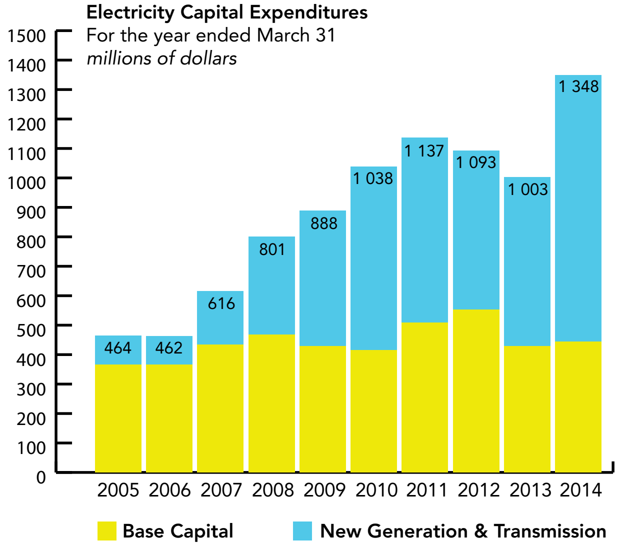
Capital and other taxes amounted to $97 million in 2013-14, an increase of $10 million or 11.5% compared to the previous year. The change was primarily due to increased capital taxes related to additional capital investment and a GST reassessment.

Other expenses include costs associated with the provision of professional consulting, operations, maintenance and project management services to external entities and other miscellaneous write-offs and expenditures. Other expenses amounted to $36 million in 2013-14, an increase of $6 million or 20.0% compared to the previous year. The increase was primarily the result of a write-off of property, plant and equipment under construction.

Electricity Capital Expenditures

Expenditures for capital construction totaled $1 348 million in 2013-14 compared to $1 003 million during the previous fiscal year. Capital expenditures for ongoing plant and equipment requirements, referred to as base capital, amounted to $444 million, an increase of $15 million compared to the previous year. The increase was attributable to higher expenditures on generating station, substation, distribution and transmission upgrades.

Electricity Capital Expenditures
For the year ended March 31
millions of dollars



Major new generation and transmission capital expenditures of $904 million included $318 million related to the Keeyask and Conawapa generation facilities, $225 million related to the Bipole III transmission line, converter stations and collector lines, $237 million towards the Pointe du Bois Spillway replacement and generating station rehabilitation, $74 million for the Riel Station, $15 million related to the Wuskwatim Generating Station and transmission line and $20 million for upgrades to the Kelsey Generating Station.

NATURAL GAS OPERATIONS

Centra Gas Manitoba Inc. (Centra) is a wholly-owned subsidiary of Manitoba Hydro. Centra distributes natural gas to 247 010 residential and 25 218 commercial and industrial customers in Manitoba.

Net income in the gas sector was $20 million in 2013-14 compared to $8 million in the previous fiscal year. The improved financial performance over the previous year was primarily attributable to increased demand due to colder weather during the winter of 2013-14 compared to the winter of 2012-13 and to a 1% distribution rate increase.

Natural Gas Revenues

Revenues from the sale and distribution of natural gas during 2013-14 were $415 million, an increase of $86 million from the previous year. After deducting the cost of gas sold, which is a pass-through cost with no mark-up by Centra, net revenues amounted to $163 million, an increase of $16 million from 2012-13. The increase in net revenue was largely due to colder weather and higher distribution rates compared to the previous year. Natural gas deliveries were 2 280 million cubic metres in 2013-14 compared to 2 049 million cubic metres in 2012-13.

As directed by the PUB, $3.8 million of revenue from 2013-14 was set aside to continue a program targeted to low-income customers and qualifying seniors on fixed incomes to assist in the replacement of low efficiency furnaces with high efficiency furnaces. At March 31, 2014, there is a remaining balance of $18 million in the Furnace Replacement Program.

Natural Gas Revenues and Deliveries

For the year ended March 31

	2014	2013	% change	2014	2013	% change
	millions of dollars			*millions of cubic metres*		
Residential	208	174	19.5	664	602	10.3
Large general service	124	95	30.5	603	523	15.3
Small general service	31	25	24.0	113	100	13.0
Large commercial & industrial	23	18	27.8	156	133	17.3
Interruptible	23	11	109.1	92	93	(1.1)
T-service and other	6	6	-	652	598	9.0
	415	329	26.1	2 280	2 049	11.3

Natural Gas Rates

In accordance with Centra's quarterly rate-setting methodology, annualized rates for natural gas supplied to residential customers changed during 2013-14 as follows:

- May 1, 2013 5.6% increase
- August 1, 2013 1.8% decrease
- November 1, 2013 1.4% increase
- February 1, 2014 6.4% increase

The change in natural gas rates reflects the fluctuations in pricing for natural gas purchased by Centra.

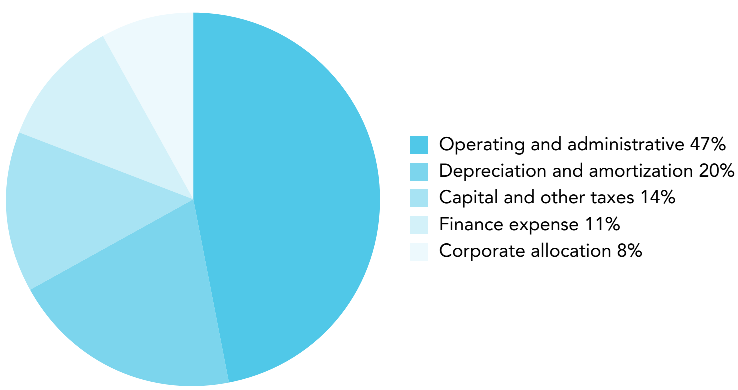
Natural gas prices have been declining since 2009 and while there have been price increases this year, the average bill is still low relative to 10 years ago. Manitoba Hydro's natural gas customers have benefited as a result. The total annual natural gas bill for a typical residential customer in Manitoba in 2013-14 was 17% lower than in 2004.

The PUB approved a general rate increase related to the non-gas costs of operating Centra of approximately 1% effective August 1, 2013. This was the first gas general rate increase implemented by Centra since May 1, 2010.

Natural Gas Expenses

Expenses attributable to the natural gas operations, excluding cost of gas sold amounted to $143 million in 2013-14, which was $4 million higher than the previous year primarily due to an increase of $3 million in operating and administrative expenses relating to pension and other benefits. In addition, there were increases of $2 million in capital and other taxes and $1 million in depreciation and amortization partially offset by a decrease of $2 million in finance expense.

Natural Gas Expenses
For the year ended March 31, 2014



Natural Gas Expenses

For the year ended March 31

	2014	2013	% change
	millions of dollars		
Operating and administrative	67	64	4.7
Finance expense	16	18	(11.1)
Depreciation and amortization	28	27	3.7
Capital and other taxes	20	18	11.1
Corporate allocation	12	12	-
	143	139	2.9

Centra purchased 886 million cubic metres of natural gas based on monthly Alberta indexed pricing, 187 million cubic metres under daily Alberta indexed pricing and 239 million cubic meters from a number of other supply sources. Centra also delivered natural gas on behalf of brokers to 15 703 (2013 – 17 418) customers receiving natural gas under Direct Purchase arrangements.

Centra offers a fixed rate service for primary natural gas supply which allows customers to fix their natural gas rates for terms of up to five years. The fixed rate service is offered to residential and commercial customers. At March 31, 2014 there were 305 customers (2013 – 396 customers) on Centra's fixed rate service. Total natural gas deliveries under this service were 6.0 million cubic metres (2013 – 6.0 million cubic metres).

Natural Gas Capital Expenditures

Capital expenditures in the natural gas sector were $35 million in 2013-14 compared to $34 million in the previous fiscal year. The capital expenditure program relates to new business, system improvement and other expenditures to meet the needs of the natural gas customers.

SUBSIDIARIES

In addition to Centra, Manitoba Hydro has the following wholly-owned subsidiaries involved in energy-related business enterprises:

Manitoba Hydro International Ltd. (MHI) provides professional consulting, operations, maintenance and project management services to energy sectors world-wide, either exclusively or through partnerships. MHI also provides research and development services and products to the electrical power system industry.

Manitoba Hydro Utility Services Ltd. (MHUS) provides meter reading and related services to Manitoba Hydro, Centra and other utilities.

The following table provides a summary of the financial results of the subsidiary companies excluding Centra for the fiscal year ended March 31, 2014 compared to the previous fiscal year:

	MHI		MHUS		Other		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
				millions of dollars				
Revenues	51.1	43.2	4.9	4.6	0.3	1.1	56.3	48.9
Expenses	43.2	38.2	4.9	4.6	0.3	0.2	48.4	43.0
Net income	7.9	5.0	-	-	-	0.9	7.9	5.9

WUSKWATIM POWER LIMITED PARTNERSHIP

The WPLP was formed to carry on the business of developing, owning and operating the Wuskwatim Generating Station and related works, excluding the transmission facilities but including all dams, dikes, channels, excavations and roads. The WPLP has two limited partners, Manitoba Hydro and Taskinigahp Power Corporation, which is owned beneficially by Nisichawayasihk Cree Nation, and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro. The Wuskwatim Generating Station is located at Taskinigahp Falls on the Burntwood River approximately 45 kilometres southwest of Thompson, Manitoba.

The WPLP reported a net loss for 2013-14 of $67 million which is consistent with the expectations for the first full year of operations. This is compared to a net loss of $40 million in 2012-13 for a partial year of operations. The net loss was mainly attributable to an increase in expenses of $49 million partially offset by an increase in revenues of $22 million resulting from the Wuskwatim generation and transmission facilities being in-service for the entire year of 2013-14 versus partial in-service in 2012-13. Manitoba Hydro's 67% share of the loss was $45 million (2013 - $27 million) and TPC's 33% share of the loss was $22 million (2013 - $13 million). At March 31, 2014 total assets for Wuskwatim generation and transmission facilities amounted to $1.6 billion (2013 – $1.6 billion).

CORPORATE PRIORITIES

The Manitoba demand for electricity is continuing to grow and new energy sources are required. To meet this increased demand, Manitoba Hydro's plan continues to include aggressively pursuing demand side options and developing clean, renewable hydro resources.

Natural gas also plays a significant role in meeting Manitoba's energy needs. During the next few years, Manitoba Hydro will be devoting a significant amount of effort in response to major changes in the North American supply and transportation markets.

Manitoba Hydro's top priorities include:

Safety in the workplace

Promoting safety in the workplace and in the actions of the public around our facilities remains Manitoba Hydro's top priority. Manitoba Hydro is committed to continuously improving its safety performance and focusing on strategies to instill a safety and health culture in all corporate activities. In doing so, Manitoba Hydro intends to maintain a steady decline in both workplace accident severity and frequency rates.

Customer value

Providing excellent customer service, high system reliability and affordable rates are fundamental in everything the corporation does. Manitoba Hydro is a leader in promoting conservation, providing numerous Power Smart Programs to assist customers in meeting their energy needs.

Financial strength

Maintaining financial strength is essential in order to make the necessary investments in infrastructure to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in Manitoba Hydro's operations and to provide customers with long-term rate stability and predictability.

Aboriginal relations

Engaging impacted Aboriginal communities in a positive way is vital to enhance working relationships. The corporation continues to place emphasis on addressing the adverse effects of our operations, fostering an appreciation of Aboriginal culture, developing and maintaining business relationships, providing opportunities in future development projects and implementing initiatives to recruit, develop and retain Aboriginal employees.

Workforce management

Attracting, developing and retaining a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to the corporation's success.

Protecting the environment

Protecting the environment is an integral part of everything Manitoba Hydro does which is accomplished by integrating environmentally responsible practices in all aspects of the business. Environmental protection is carried out with dedication to monitoring programs, climate change initiatives, and environmental research and development.

Demand side management (DSM)

As the province's population and economy continues to grow, DSM plays a key role in meeting Manitoba's future energy needs in a sustainable manner. These efforts assist customers in using energy more efficiently and result in overall lower energy bills.

REPORT ON PERFORMANCE

The report on performance summarizes progress the corporation is making towards top priorities in achieving operational excellence.

Priorities	Measure	Target / Challenge	2014 Performance
Safety in the workplace	Accident severity rate (days per 200 000 hours worked)	<12	11.1
	Accident frequency rate (accidents per 200 000 hours worked)	<0.6	0.7
	High-risk accidents	0	0
Customer value	System average interruption duration (minutes per year)	<116	106.5
	System average interruption frequency (outages per year)	<1.4	1.26
	Customer satisfaction	>8.4/10 customer satisfaction	7.87
Financial strength	Debt:equity ratio	75:25	76:24
	Interest coverage	>1.20	1.28
	Capital coverage	>1.20	1.35
Workforce management	Women	26%	24.5%
	Aboriginal – corporate	16%	17.6%
	Aboriginal – northern	45%	44.1%
	Persons with disabilities	6%	9.9%
	Visible minorities	7%	7.8%
Protecting the environment	Percentage of electricity generated in Manitoba from renewable resources	≥99%	99.6%
	Total annual GHG emissions	≤520 kt	163 kt
	Repeat environmental audit findings	0 repeat findings	0
Demand side management	Electric energy saved - GWh annual incremental savings	174 GWh	308 GWh
	Electric capacity saved - MW annual incremental savings	201 MW	278 MW
	Natural gas energy saved - in millions of cubic metres saved annually	10 million cubic metres	8.5 million cubic metres

RISK MANAGEMENT

Manitoba Hydro faces a number of risks in the fulfillment of its mission and mandate. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of:

- identifying threats that affect the achievement of the corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on reducing the occurrence of negative events. However, the corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or natural disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of new infrastructure development, aging infrastructure maintenance and replacement, weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, increasing regulatory, environmental and legal requirements and accelerated technological change. Manitoba Hydro manages these risks through an integrated control framework and through the maintenance of an adequate level of retained earnings.

Manitoba Hydro's most significant risks are quantified in the following table:

Risk	Potential Financial Impact
Infrastructure	Greater than $2.0 billion
Drought	Greater than $1.6 billion for a five year drought
Loss of export market	Greater than 30% of electricity revenue
Interest rates	Approximately $900 million for a 1% change over 10 years

STATUS OF TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February 2013, the Canadian Accounting Standards Board (AcSB) announced an additional optional one-year deferral of IFRS for qualifying entities with rate-regulated activities with year-ends beginning after January 1, 2015. Manitoba Hydro meets the AcSB criteria for deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

The corporation expects the transition to IFRS to impact accounting, financial reporting and related information systems. Reporting of the conversion status is provided to the Audit Committee of the Manitoba Hydro-Electric Board.

Although IFRS and Canadian Generally Accepted Accounting Principles (GAAP) are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Manitoba Hydro include property, plant and equipment, regulatory assets and liabilities, employee benefits and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

On January 30, 2014, the International Accounting Standards Board (IASB) approved a new interim standard IFRS 14, Regulatory Deferral Accounts which is effective January 1, 2016 with earlier adoption permitted. The new standard applies only to entities that are first-time adopters of IFRS, conduct rate-regulated activities and recognize regulatory deferral account balances in their financial statements in accordance with their previous GAAP. Manitoba Hydro's operations fall within the scope of the new interim standard and it will early adopt IFRS 14 upon its transition to IFRS effective April 1, 2015.

In adopting the new interim standard IFRS 14, Manitoba Hydro will:

- continue to use its previous GAAP accounting policies for the recognition, measurement and impairment of regulatory deferral account balances;
- present regulatory deferral account balances as separate line items in the statement of financial position and to present movements in those account balances as a separate line item in the statement of profit or loss and other comprehensive income; and
- provide specific disclosures to identify clearly the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances.

Notably, the new interim standard is only intended to provide temporary guidance until the IASB completes its comprehensive project on Rate-regulated Activities. It is expected that the comprehensive project may take several years to complete.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-regulated Activities project. In addition, the IASB has a number of ongoing projects on its agenda which may result in changes to existing IFRS prior to the commencement of Manitoba Hydro's 2015-16 fiscal year. Manitoba Hydro continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

OUTLOOK

Manitoba Hydro entered fiscal 2014-15 with above average water storage levels and expectations for the spring runoff for 2014 are above average. However, Manitoba Hydro expects its net income for 2014-15 to be significantly below the level experienced in 2013-14. This results from lower forecast revenue assuming normal winter weather conditions and higher forecast depreciation and finance expense due to continued investment in property, plant and equipment.

Manitoba Hydro has commenced construction of the Bipole III transmission line and is actively planning a number of major projects such as Keeyask and Conawapa generating stations in order to further improve electrical system reliability, to meet the future energy needs of the province and to take advantage of export opportunities. These plans will involve the investment of approximately $20 billion which will generate significant returns for Manitobans over ensuing decades. Construction of the new generating stations will only proceed once firm export sales contracts are secured, extensive consultations with stakeholders and First Nations are concluded and environmental and regulatory approvals are received.

The Bipole III project involves the construction of a new 500-kV high voltage direct current transmission line along with new converter stations, one in the north and another at the southern receiving end. The project is required to improve system reliability and will also provide additional capacity for delivery of existing and proposed hydro-electric generation to southern markets. The Manitoba Environment Act license for Bipole III was issued in August 2013 following the Manitoba Clean Environment Commission (CEC) public hearing and report. Construction has started on the Keewatinoow (northern) converter station, construction power station and line as well as the clearing of the right-of-way for northern segments of the 500-kV transmission line.

In accordance with Manitoba Order in Council No. 128/2013, a Needs For and Alternatives To review is being undertaken by the PUB of the economic and societal justification for Manitoba Hydro's proposed development plan including Keeyask, Conawapa, a new Manitoba to U.S. transmission interconnection and new long-term export sales. Public hearings commenced March 2014 and are expected to conclude in May with a report to be submitted to the Minister responsible for the Public Utilities Board Act by June 2014.

The 695-megawatt Keeyask Generating Station would be built on the Nelson River, 30 kilometres west of Gillam, within the Split Lake Resource Management Area, in partnership with four Keeyask Cree Nations (KCN) – Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. A Keeyask Infrastructure Agreement was negotiated between Manitoba Hydro and KCN enabling an early start to the construction of the access road to the site and the construction camp. The CEC hearings to review the Keeyask Generating Station project's environmental impact statement concluded in January 2014. The Minister of Conservation and Water Stewardship released the report on the Keeyask Generation Project in May 2014 recommending that the project be issued a license under the Manitoba Environment Act. Pending regulatory approvals, construction is scheduled to start in the summer of 2014 with an in-service date of 2019.

The proposed 1 485-megawatt Conawapa Generating Station would be built approximately 90 kilometres downstream of Gillam and 28 kilometres downstream of the Limestone Generating Station, in the Fox Lake Resource Management Area on the Lower Nelson River. A formal planning process is underway with the communities in the vicinity of the project, including Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, War Lake First Nation and Shamattawa First Nation. Activities are progressing to complete the Project Description, preliminary engineering and the environmental assessment. Discussions on Aboriginal participation are taking place with Fox Lake Cree Nation and are expected to begin with the rest of the in-vicinity communities during fiscal 2015. The Environmental Impact Statement is scheduled to be filed by the end of 2015 with the potential start of construction in January 2018, which would support an earliest in-service date of 2026.

Manitoba Hydro's highly successful Power Smart Program continues to encourage residential, commercial and industrial customers to use energy more efficiently through 30 programs and initiatives. These efforts work towards making permanent shifts in the Manitoba marketplace for long-term adoption of energy efficient technologies and practices. The Program forecasts higher energy savings through expanding on the existing portfolio with a more aggressive approach to delivering existing programs and by pursuing additional emerging opportunities. The Program is projected to achieve electric energy and demand savings of 6 286 GWh and 1 635 MW per year and natural gas savings of 211 million cubic metres per year by 2028-29. These energy savings are expected to reduce greenhouse gas emissions by over 4.6 million tonnes annually while providing Manitobans with lower energy bills from the installation of energy savings measures and the continued sale of the conserved energy on export markets. The reduced energy consumption forecast in the plan represents 12.7% of the estimated electric load forecast offsetting 66% of projected load growth during this period and 5.3% of the estimated natural gas volume forecast by 2028-29, further reducing natural gas consumption in Manitoba.

Refurbishing a manhole in downtown Winnipeg.

MANAGEMENT REPORT

For the year ended March 31, 2014

The accompanying consolidated financial statements and all additional information contained in the Annual Report are the responsibility of management and have been approved by the Manitoba Hydro-Electric Board. The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada, applied on a basis consistent with that of the preceding year. In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality, incorporating management's best judgment regarding all necessary estimates and all other data available up to June 25, 2014. The financial information presented elsewhere in the Annual Report is consistent with that in the consolidated financial statements.

Management maintains internal controls to provide reasonable assurance that the assets of the corporation are properly safeguarded and that the financial information is reliable, timely and accurate. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its finding to management and to the Audit Committee of the Board.

The responsibility of the external auditors, Ernst & Young LLP, is to express an independent, professional opinion on whether the consolidated financial statements are fairly presented in accordance with Canadian generally accepted accounting principles. The Auditors' Report outlines the scope of their examination and their opinion.

The Audit Committee of the Board is comprised of five members, the majority of whom are members of the Manitoba Hydro-Electric Board. The Audit Committee of the Board meets with the external auditors, representatives of the Auditor General's Office, the internal auditors and management to satisfy itself that each group has properly discharged its respective responsibility and to review the consolidated financial statements before recommending approval by the Board. The internal and external auditors have full and unrestricted access to the Audit Committee, with or without the presence of management. The Board reviews the Annual Report in advance of its release and approves its content and authorizes its publication.

On behalf of management:

Scott A. Thomson, CA
President and Chief Executive Officer

Darren B. Rainkie, CA, CBV
Vice-President, Finance and Regulatory

Winnipeg, Canada
June 25, 2014

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Manitoba Hydro-Electric Board

We have audited the accompanying consolidated financial statements of **Manitoba Hydro-Electric Board**, which comprise the consolidated balance sheet as at March 31, 2014 and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Manitoba Hydro-Electric Board as at March 31, 2014 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Winnipeg, Canada,
June 25, 2014

Ernst & Young LLP

Chartered Accountants

CONSOLIDATED STATEMENT OF INCOME

For the year ended March 31

		Notes	2014	2013
			millions of dollars	
Revenues				
Electric	Manitoba		1 405	1 341
	Extraprovincial	4	439	353
	Other revenue	8	70	69
Gas	Commodity		252	182
	Distribution		163	147
			2 329	2 092
Cost of gas sold			252	182
			2 077	1 910
Expenses				
Operating and administrative			557	533
Finance expense		5	471	489
Depreciation and amortization		6	442	423
Water rentals and assessments		7	125	118
Fuel and power purchased			177	133
Capital and other taxes			117	105
Other expenses		8	36	30
			1 925	1 831
Net income before non-controlling interest			152	79
Net loss attributable to non-controlling interest		25	22	13
Net Income			174	92

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2014	2013
	millions of dollars	
Retained earnings, beginning of year	2 542	2 450
Net income	174	92
Retained earnings, end of year	2 716	2 542

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEET

As at March 31

	Notes	2014	2013
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	9	16 190	15 793
Less accumulated depreciation	9	5 506	5 252
		10 684	10 541
Construction in progress	9	2 943	1 967
		13 627	12 508
Current Assets			
Cash and cash equivalents		142	32
Accounts receivable and accrued revenue		520	421
Interest receivable		-	4
Materials and supplies, at average cost	10	81	93
		743	550
Other Assets			
Sinking fund investments	11	111	352
Goodwill and intangible assets	12	281	276
Regulated assets	13	360	306
Other long-term assets	14	517	550
		1 269	1 484
		15 639	14 542

Approved on behalf of the Board:

William C. Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

	Notes	2014	2013
		millions of dollars	
Liabilities and Equity			
Long-Term Debt			
Long-term debt net of sinking fund investments		10 349	8 977
Sinking fund investments shown as assets	11	111	352
	15	10 460	9 329
Current Liabilities			
Accounts payable and accrued liabilities		561	397
Accrued interest		100	103
Current portion of long-term debt	15	408	656
		1 069	1 156
Other Liabilities			
Asset purchase obligation	16	207	207
Regulated liabilities	13	22	24
Other long-term liabilities	17	615	550
		844	781
Contributions in Aid of Construction	18	381	340
Equity			
Retained earnings		2 716	2 542
Accumulated other comprehensive income		96	299
		2 812	2 841
Non-controlling interest	25	73	95
		2 885	2 936
		15 639	14 542

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended March 31

	2014	2013
	millions of dollars	
Operating Activities		
Cash receipts from customers	2 198	2 015
Cash paid to suppliers and employees	(1 070)	(981)
Interest paid	(510)	(489)
Interest received	72	44
Cash provided by operating activities	690	589
Financing Activities		
Proceeds from long-term debt	1 320	807
Sinking fund withdrawals	415	129
Retirement of long-term debt	(613)	(242)
Other	(21)	(59)
Cash provided by financing activities	1 101	635
Investing Activities		
Property, plant and equipment, net of contributions	(1 383)	(1 037)
Sinking fund payments and deposits	(209)	(107)
Other	(89)	(98)
Cash used for investing activities	(1 681)	(1 242)
Net increase (decrease) in cash and cash equivalents	110	(18)
Cash and cash equivalents, beginning of year	32	50
Cash and cash equivalents, end of year	142	32

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year ended March 31

	2014	2013
	millions of dollars	
Net Income	174	92
Other Comprehensive Loss		
Unrealized foreign exchange losses on debt in cash flow hedges	(155)	(31)
Realized foreign exchange (gains) losses on debt in cash flow hedges reclassified to income	(19)	2
Realized gains on early redemption of sinking funds recognized in net income	(19)	-
Unrealized fair value gains (losses) on available-for-sale U.S. sinking fund investments	(10)	1
	(203)	(28)
Comprehensive Income (Loss)	(29)	64

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME

For the year ended March 31

	2014	2013
	millions of dollars	
Accumulated other comprehensive income, beginning of year	299	327
Other comprehensive loss	(203)	(28)
Accumulated other comprehensive income, end of year	96	299

The accompanying notes are an integral part of the consolidated financial statements.

NOTE 1 NATURE OF THE ORGANIZATION

The Manitoba Hydro-Electric Board and the Manitoba Power Commission were amalgamated in 1961 by enactment of *The Manitoba Hydro Act* to form a Crown Corporation in the Province of Manitoba named Manitoba Hydro (the corporation). Manitoba Hydro's mandate is to provide for the continuance of a supply of energy adequate for the needs of the province and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy. The head office of the corporation is located at 360 Portage Avenue, Winnipeg, Manitoba.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation - These consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting - Pre-Changeover Accounting Standards and include the significant accounting policies described hereafter.

Consolidation - These consolidated financial statements include the accounts of Manitoba Hydro and its wholly-owned subsidiaries including Centra Gas Manitoba Inc. (Centra), Minell Pipelines Ltd., Manitoba Hydro International Ltd. (MHI), Manitoba Hydro Utility Services Ltd. (MHUS), Teshmont LP Holdings Ltd. (which has a 40% ownership interest in the Teshmont Consultants Limited Partnership) and 6690271 Manitoba Ltd. (a subsidiary which was formed to participate in the development of a new transmission interconnection to the U.S.). These consolidated financial statements also include Manitoba Hydro's 67% ownership interest in the Wuskwatim Power Limited Partnership (WPLP) and its 75% ownership in the Keeyask Hydropower Limited Partnership. For purposes of consolidation, all significant intercompany accounts and transactions have been eliminated.

Rate-Regulated Accounting - The prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the Public Utilities Board of Manitoba (PUB). The rate-setting process is designed such that rates charged to electricity and natural gas customers recover costs incurred by Manitoba Hydro in providing electricity and gas service. As permitted under Canadian GAAP, the corporation applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of Canadian GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Manitoba Hydro applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise have been included in the determination of net income in the year that the cost or credit is incurred. Manitoba Hydro refers to such deferred costs or credits as regulated assets or regulated liabilities (Note 13) which are generally comprised of the following:

- Power Smart programs - The costs of the corporation's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.

- Site restoration costs - Site restoration costs, other than those for which an asset retirement obligation has been established, are deferred and amortized on a straight-line basis over a period of 15 years.

- Deferred taxes - Taxes paid by Centra (July 1999) as a result of its change to non-taxable status on acquisition by Manitoba Hydro, have been deferred and are being amortized on a straight-line basis over a period of 30 years.

- Acquisition costs - Costs associated with the acquisition of Centra (July 1999) and Winnipeg Hydro (September 2002) have been deferred and are being amortized on a straight-line basis over a period of 30 years.

- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.

- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. The difference between the recorded cost of natural gas and the actual cost of natural gas is recovered or refunded in future rates.

- Demand side management (DSM) deferral - In Board Orders 43/13 and 85/13, the PUB directed that the differences between actual and planned spending on electric and gas DSM for the 2012-13 and 2013-14 fiscal years be recorded in a regulatory deferral account. The cumulative differences for 2012-13 and 2013-14 have been recorded as a regulated liability with an offsetting balance recorded as a regulated asset. The disposition of this regulatory deferral will be determined at a future PUB proceeding.

Manitoba Hydro's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**

Property, plant and equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases and depreciation and interest charged to operations commences.

b) **Depreciation**

Depreciation is provided on a straight-line remaining-life basis. The major components of generating stations are depreciated over the lesser of the remaining life of the major component or the remaining life of the associated generating station.

The range of estimated service lives of each major asset category is as follows:

Generation	-	Hydraulic	20 - 125 years
	-	Thermal	5 - 65 years
Transmission lines			10 - 85 years
Substations			15 - 65 years
Distribution			10 - 75 years
Other			5 - 100 years

Provision for removal costs of major property, plant and equipment is charged to depreciation expense on a straight-line basis over the remaining service lives of the related assets. Retirements of these assets, including costs of removal, are charged to accumulated depreciation with no gains or losses reflected in operations. The estimated service lives and removal costs of the assets are based upon depreciation studies conducted periodically by the corporation.

c) **Asset Retirement Obligations**

Asset retirement obligations are measured initially at fair value in the period in which the obligations are incurred, provided that a reasonable estimate of the fair value can be made. The present value of the estimated retirement cost is added to the carrying amount of the related asset. In subsequent periods, the estimated retirement cost is amortized over the useful life of the asset and the carrying value of the liability is increased to recognize increases in the liability's present value with the passage of time.

d) **Materials and Supplies**

Materials and supplies are valued at the lower of average cost or net realizable value.

e) **Contributions in Aid of Construction**

Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

f) **Revenues**

Manitoba electricity and gas sales are recognized upon delivery to the customer and include an estimate of energy deliveries not yet billed at year-end.

Extraprovincial revenues are recorded upon the delivery of energy.

Other revenue is recorded on the delivery of the related good or service, over the term of the contract for maintenance and lease contracts or on a percentage of completion basis for fixed price contracts.

g) **Cost of Gas Sold**

Cost of natural gas sold is recorded at the same rates charged to customers.

h) **Employee Future Benefits**

Manitoba Hydro provides future benefits, including pension and other post-retirement benefits, to both existing and retired employees. Pension plans include the Civil Service Superannuation Board (CSSB) plan, the Enhanced Hydro Benefit Plan (EHBP), three Centra curtailed pension plans and the Winnipeg Civic Employee Benefits Program (WCEBP). MHUS is a matching employer under the Civil Service Superannuation Act and MHI sponsors a defined contribution group registered retirement plan.

The costs and obligations of pension and other post-retirement benefits are calculated by an independent actuary using the accrued benefit actuarial cost method and reflect management's best estimate of future compensation increases, service lives, inflation rates and expected rate of return on plan assets. Pension expense is comprised of the cost of pension benefits provided during the year, the amortization of past service benefits, experience gains and losses and expected returns on fund assets net of interest on the obligation. The amount of expected returns on fund assets is based on market related values using a five-year moving average. The unamortized present value of past service benefits and actuarially determined experience gains or losses are recognized in the consolidated financial statements as assets or liabilities.

The corporation utilizes the "corridor method" of amortizing actuarial gains and losses. The amortization of experience gains and losses is recognized only to the extent that the cumulative unamortized net actuarial gain or loss exceeds 10% of the greater of the accrued benefit obligation and the fair market value of plan assets at the beginning of the year. When required, the excess of the cumulative gain or loss balance is amortized over the expected average remaining service life of the employees covered by the plan.

Pension and long-term disability expenses pertaining to the former Winnipeg Hydro employees are recognized at the time contributions are made to the WCEBP, which maintains the funds and obligations relating to these employees in its financial records.

Other employee benefits earned by employees include vacation, vested sick leave, severance and a retirement health spending plan. Where applicable, the future costs of these benefits are based on management's best estimates.

i) **Comprehensive Income**

Comprehensive income consists of net income and other comprehensive income (OCI). OCI includes unrealized gains and losses arising from changes in the fair value of available-for-sale assets and changes in the foreign exchange rate for U.S. denominated long-term debt and interest payments in effective cash flow hedging relationships. Such amounts are recorded in accumulated OCI (AOCI) until the criteria for recognition in net income are met.

j) **Financial Instruments**

All financial instruments are measured at fair value on initial recognition as of the trade date. Transaction costs are included in the initial carrying amount of financial instruments. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale or other financial liabilities.

Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are measured at fair value with unrealized gains and losses recorded in OCI until the instrument is derecognized or impaired. Translation gains and losses on available-for-sale financial assets in a hedging relationship with financial liabilities are credited or charged to finance expense. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in income in the period in which they arise.

k) **Foreign Currency Translation**

Revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollar equivalents at exchange rates in effect at the transaction dates.

Long-term monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date. Translation gains and losses are credited or charged to finance expense in the current period except for long-term debt obligations in hedging relationships with future export revenues. Translation gains and losses for long-term debt obligations in hedging relationships with future export revenues are recorded in OCI until such time that the hedged export revenues are realized, at which time accumulated exchange gains and losses are credited or charged to finance expense.

Current monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing as at the consolidated balance sheet date. Any exchange gains and losses on the translation of current monetary assets and liabilities are credited or charged to finance expense in the current period.

l) **Derivatives**

The corporation does not engage in derivative trading or speculative activities. All derivative instruments are carried at fair value on the consolidated balance sheet with the exception of those that were entered into for the purpose of physical receipt or delivery in accordance with the corporation's expected normal purchases and sales. Changes in the fair value of derivatives that are not designated in a hedging relationship and do not qualify for the normal purchase and sale exemption are recorded in net income.

m) **Hedges**

The corporation has designated cash flow and fair value hedges linking financial instruments to specific assets and forecasted transactions. Long-term cash flow hedges have been established between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. A fair value hedge relationship has also been established between U.S. long-term debt balances and U.S. sinking fund investments. The corporation documents the relationship between the hedging instrument and the hedged item and assesses at inception, and on an ongoing basis, the effectiveness of the hedging relationship.

n) **Debt Discounts and Premiums**

Debt discounts and premiums are amortized to finance expense using the effective interest method.

o) **Cash and Cash Equivalents**

Cash and cash equivalents include cash on hand and short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

p) **Goodwill and Intangible Assets**

Goodwill represents the amount of the corporation's investments in Centra and Winnipeg Hydro over and above the fair market value of the identified net assets acquired. The goodwill balance is evaluated annually to determine whether any impairment has occurred. An impairment would be recognized if it was determined that the carrying value of the corporation's investments in Centra or Winnipeg Hydro exceeded the present value of the future cash flows from these investments. Should impairment occur, it would be recorded as a charge against operations in the year of impairment.

Intangible assets include computer software, application development costs, land easements and transmission rights. Intangible assets are recorded at cost. The cost of computer software and application development includes software, direct labour, materials, contracted services, a proportionate share of overhead costs and interest during development applied at the average cost of debt. Intangible assets with finite useful lives are amortized over their useful lives on a straight-line basis. The expected useful lives are as follows:

Computer software and application development	5 – 10 years
Land easements	75 years
Transmission rights	1 – 12 years

The estimated service lives of intangible assets are based upon depreciation studies conducted periodically by the corporation. The transmission rights are amortized over the contractual period plus a one-term renewal.

q) **Non-Controlling Interest**

Non-controlling interest represents the outstanding ownership interests attributable to third parties in the corporation's limited partnerships. The portion of the equity not owned by the corporation is reflected as non-controlling interest within the equity section of the consolidated balance sheet. The portion of the net income or net loss not attributed to the corporation is recorded as a non-controlling interest in the consolidated statement of income.

r) **Use of Estimates**

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Actual amounts could differ from those estimates, but differences are not expected to be material.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Manitoba Hydro would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Manitoba Hydro include property, plant and equipment, regulatory assets and liabilities, employee benefits and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus Improvements to IFRS, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Manitoba Hydro intends to apply this exemption.

In September 2010, the AcSB implemented changes to Part I of the CPA Canada Handbook – International Financial Reporting Standards allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Manitoba Hydro meets the AcSB criteria for deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On January 30, 2014, the IASB issued the interim standard IFRS 14 *Regulatory Deferral Accounts* for rate-regulated activities effective January 1, 2016 with earlier adoption permitted. Manitoba Hydro will early adopt the interim standard upon transition to IFRS effective April 1, 2015 and will continue to recognize regulatory deferral accounts for its financial reporting.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-Regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in modifications to existing IFRS prior to the commencement of Manitoba Hydro's 2015-16 fiscal year. Manitoba Hydro continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

NOTE 4 EXTRAPROVINCIAL REVENUES

U.S. extraprovincial revenues were translated into Canadian dollars at exchange rates in effect at the date of the

	2014	2013
	millions of dollars	
United States	392	312
Canada	47	41
	439	353

transaction. The average effective exchange rate for the year was $1.00 U.S. = $1.05 Canadian (2013 - $1.00 U.S. = $1.00 Canadian).

NOTE 5 FINANCE EXPENSE

	2014	2013
	millions of dollars	
Interest on debt	654	636
Interest capitalized	(142)	(141)
Investment income	(24)	(11)
Realized foreign exchange (gains) losses on debt in cash flow hedges	(19)	2
Realized losses on revaluation of dual currency bonds	2	3
	471	489

Included in interest on debt is $99 million (2013 - $93 million) related to the Provincial Debt Guarantee Fee. The fee during the year was 1.0% of the total outstanding debt guaranteed by the Province of Manitoba (2013 - 1.0%).

NOTE 6 DEPRECIATION AND AMORTIZATION

	2014	2013
	millions of dollars	
Depreciation of property, plant and equipment	375	359
Amortization of regulated assets	45	42
Amortization of intangible assets	22	22
	442	423

NOTE 7 WATER RENTALS AND ASSESSMENTS

	2014	2013
	millions of dollars	
Water rentals	118	111
Assessments	7	7
	125	118

Water rentals are paid to the Province of Manitoba for the use of water resources in the operation of the corporation's hydro-electric generating stations. Water rental rates during the year were $3.34 per MWh (2013 - $3.34 per MWh).

NOTE 8 OTHER REVENUE AND OTHER EXPENSES

	2014	2013
	millions of dollars	
Other revenue		
Services provided to external entities	52	45
Miscellaneous revenue	18	24
	70	69
Other expenses		
Cost of services provided to external entities	32	30
Write-off of property, plant and equipment under construction	4	-
	36	30

NOTE 9 PROPERTY, PLANT AND EQUIPMENT

	2014			2013		
	millions of dollars					
	In service	Accumulated depreciation	Construction in progress	In service	Accumulated depreciation	Construction in progress
Generation						
Hydraulic	6 772	1 825	1 788	6 645	1 739	1 222
Thermal	479	290	17	480	277	11
Transmission lines	1 036	319	249	1 024	311	127
Substations	3 055	1 407	731	2 977	1 337	489
Distribution	3 634	1 287	114	3 471	1 242	95
Other	1 214	378	44	1 196	346	23
	16 190	5 506	2 943	15 793	5 252	1 967

NOTE 10 MATERIALS AND SUPPLIES

	2014	2013
	millions of dollars	
Materials and supplies	81	72
Natural gas inventory	-	21
	81	93

NOTE 11 SINKING FUND INVESTMENTS

Manitoba Hydro is legislated under *The Manitoba Hydro Act* to make annual sinking fund payments to the Province of Manitoba of not less than 1% of the principal amount of the outstanding debt on the preceding March 31 and 4% of the balance in the sinking fund at such date. Payments to the sinking fund during the year were $209 million (2013 - $107 million). Income earned on sinking fund investments is included with investment income for the year.

Sinking funds are invested in government bonds and the bonds of highly rated corporations and financial institutions.

	2014	2013
		millions of dollars
U.S. investments	111	272
Canadian investments	-	58
Premium on purchase of sinking fund investments	-	22
	111	352

U.S. investments have a weighted average term to maturity of 10 days (2013 - 4.0 years) and an effective yield to maturity of 0.1% (2013 – 3.7%). U.S. investments are translated into Canadian dollars at the exchange rate prevailing as at the consolidated balance sheet date, $1.00 U.S. = $1.11 Canadian (2013 - $1.00 U.S. = $1.02 Canadian). The March 31, 2014 balance includes nil (2013 - $29 million) of unrealized fair value gains. Canadian investments have a weighted average term to maturity of 1 day (2013 - 1 day) and an effective yield to maturity of 1.0% (2013 - 1.1%).

NOTE 12 GOODWILL AND INTANGIBLE ASSETS

	2014			2013		
			millions of dollars			
	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
Intangible assets						
Computer software and application development	222	120	102	210	105	105
Land easements	80	14	66	72	13	59
Transmission rights	8	3	5	5	1	4
	310	137	173	287	119	168
Goodwill	108	-	108	108	-	108
	418	137	281	395	119	276

The additions to intangible assets for the year totaled $30 million (2013 - $31 million). In total, intangible assets of $24 million (2013 - $23 million) were amortized to operations during the year.

NOTE 13 REGULATED ASSETS AND REGULATED LIABILITIES

		2014	2013
		millions of dollars	
Regulated assets			
Power Smart programs	- electric	184	172
	- gas	54	47
Purchased gas variance accounts		39	-
Site restoration costs		36	35
Deferred taxes		27	29
Acquisition costs		19	20
Regulatory costs		1	3
		360	306
Regulated liabilities			
DSM deferral		22	-
Purchased gas variance accounts		-	24
		22	24

If the corporation was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and net income for 2014 would have been increased by $7 million (2013 – increased by $4 million).

In total, regulated assets of $49 million (2013 - $46 million) were amortized to operations during the year.

The corporation passes all costs related to the purchase and transportation of natural gas on to its customers without markup. If the corporation were not subject to rate regulation, the purchased gas variance accounts would not be maintained and the actual cost of gas would be expensed in the period incurred. If actual gas costs were expensed and sales rates were not adjusted accordingly, net income would have decreased by $63 million (2013 - decreased by $6 million).

NOTE 14 OTHER LONG-TERM ASSETS

	2014	2013
	millions of dollars	
Advances to St. Joseph Windfarm Inc. (excluding current portion)	218	227
Advances to Taskinigahp Power Corporation (Note 25)	112	105
Accrued benefit asset (Note 21)	90	122
Contract receivables	86	81
Affordable Energy Fund (Note 24)	11	15
	517	550

The St. Joseph wind farm is owned by Pattern Energy and operated by St. Joseph Windfarm Inc. Financing for the wind farm was provided partly by Manitoba Hydro. In accordance with the loan agreement, Manitoba Hydro provided advances of $250 million, which will be repaid with interest over 20 years. In addition, Manitoba Hydro has provided access to a $10 million reserve loan facility. The corporation signed a 27-year power purchase agreement with St. Joseph Windfarm Inc. in March 2010.

NOTE 15 LONG-TERM DEBT

	2014	2013
	millions of dollars	
Advances from the Province of Manitoba		
represented by debenture debt of the Province	10 683	9 775
Manitoba HydroBonds	169	55
Manitoba Hydro-Electric Board Bonds	158	182
	11 010	10 012
Less: Current portion of long-term debt	408	656
	10 602	9 356
Adjustment to carrying value of dual currency bonds	(12)	(20)
Debt discounts and premiums	(96)	22
Transaction costs	(34)	(29)
	10 460	9 329

During the year, the corporation arranged long-term financing of $1 320 million (2013 - $807 million). The current year financing was in the form of Provincial Advances with the majority at fixed interest rates.

Included in the current portion of long-term debt are $259 million (2013 - $617 million) of debt maturities and $149 million (2013 - $39 million) of floating-rate Manitoba HydroBonds with maturity dates in 2016 and 2018. Floating rate Manitoba HydroBonds are redeemable at the option of the holder.

Long-term debt is guaranteed by the Province of Manitoba, with the exception of Manitoba Hydro-Electric Board Bonds in the amount of $65 million (2013 - $73 million) issued for mitigation projects.

Debt principal amounts (excluding adjustments to the carrying value of dual currency bonds, transaction costs, debt discounts and premiums) and related yields are summarized by fiscal years of maturity in the following table:

					2014	2013
		millions of Canadian dollars				
Years of Maturity	Canadian	Cdn. Yields	U.S.	U.S. Yields	Total	Total
2015	298	2.6%	110	2.7%	408	210
2016	313	4.3%	-	-	313	313
2017	311	3.4%	-	-	311	308
2018	331	6.8%	-	-	331	331
2019	905	5.6%	442	10.0%	1 347	1 319
	2 158	5.0%	552	10.0%	2 710	2 481
2020-2024	1 125	3.6%	1 326	6.5%	2 451	2 044
2025-2029	510	6.1%	-	-	510	510
2030-2034	990	8.8%	-	-	990	989
2035-2039	1 425	4.9%	-	-	1 425	1 425
2040-2044	1 600	4.4%	-	-	1 600	1 350
2045-2063	1 324	4.1%	-	-	1 324	557
	9 132	4.9%	1 878	7.1%	11 010	9 356

Included in the above Canadian maturity amounts is one dual currency bond with the principal amount repayable in Canadian currency and interest payments denominated in U.S. currency. The dual currency bond matures in the 2025-26 fiscal year in the amount of $130 million Canadian.

U.S. debt is translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date, $1.00 U.S. = $1.11 Canadian (2013 - $1.00 U.S. = $1.02 Canadian).

NOTE 16 ASSET PURCHASE OBLIGATION

Effective September 3, 2002, the corporation acquired the net assets of Winnipeg Hydro from the City of Winnipeg. The asset purchase obligation represents the net present value of payments to the City of Winnipeg of $16 million per annum in perpetuity.

NOTE 17 OTHER LONG-TERM LIABILITIES

	2014	2013
	millions of dollars	
Mitigation liability (Note 23)	229	235
Accrued benefit liability (Note 21)	188	174
Refundable advances from customers	102	96
Transmission community development initiatives	67	15
Asset retirement obligations	13	9
Affordable Energy Fund (Note 24)	11	15
Other	5	6
	615	550

The corporation recorded liabilies for the transmission community development initiatives for both the Wuskwatim transmission line and the Herblet Lake transmission line as outlined in the Wuskwatim Project Development Agreement of $16 million (2013 – $15 million) and for the Bipole III community development initiatives of $51 million (2013 – nil). These funds will be used for community development purposes by eligible First Nations and small or remote northern communities in the vicinity of the transmission lines.

Asset retirement obligations continue to be recognized for the future decommissioning of the Brandon Thermal Generating Station and for the partial decommissioning of the Pointe du Bois Generating Station spillway. The corporation estimates the undiscounted cash flows required to settle the asset retirement obligations are approximately $21 million (2013 - $17 million), $15 million (2013 - $15 million) of which is expected to be incurred in 2024 to decommission the Brandon Thermal Generating Station and $6 million (2013 - $2 million) is expected to be incurred by March 2015 for the partial decommissioning of the Pointe du Bois Generating Station spillway. No funds are being set aside to settle the asset retirement obligations.

NOTE 18 CONTRIBUTIONS IN AID OF CONSTRUCTION

	2014	2013
	millions of dollars	
Contributions in aid of construction	362	340
Bipole III contribution	19	-
	381	340

Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

In Order 43/13, dated April 26, 2013, the PUB directed that 1.5% of the approved 3.5% rate increase effective May 1, 2013 be set aside to be utilized to mitigate the required rate increases when Bipole III is placed in-service. During the 2013-14 fiscal year $19 million was set aside for this purpose. The period over which this balance will be recognized into net income will be determined by the PUB at a future regulatory proceeding.

NOTE 19 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of the corporation's non-derivative financial instruments at March 31 were as follows:

	2014		2013	
Financial Instruments	Carrying value	Fair value	Carrying value	Fair value
	millions of dollars			
Held-for-trading				
Cash and cash equivalents	142	142	32	32
Loans and receivables				
Accounts receivable and accrued revenue	520	520	421	421
Interest receivable	-	-	4	4
Available-for-sale				
Sinking fund investments	111	111	352	352
Other financial liabilities				
Long-term debt (including current portion)	10 868	12 592	9 985	12 335
Accounts payable and accrued liabilities	561	561	397	397
Accrued interest	100	100	103	103
Asset purchase obligation	207	319	207	343

The fair value measurement of financial instruments is classified in accordance with a hierarchy of three levels, based on the type of inputs used in making these measurements:

Level 1 - Quoted prices in active markets for identical assets and liabilities;
Level 2 - Inputs other than quoted prices that are observable in active markets for the asset or liability; and
Level 3 - Inputs for the asset or liability that are not based on observable market data.

Financial instrument measurements are Level 1 measurements with the exception of the long-term debt and the asset purchase obligation that are Level 2 measurements and certain derivative instruments of nominal value associated with wholesale power marketing activities that are Level 3 measurements. Fair value Level 2 measurements are derived from quoted market yields at the close of business on the consolidated balance sheet date for similar instruments available in the capital market. Level 3 measurements are based on internally developed valuation models which are consistent with valuation models developed by other market participants in the wholesale power markets. The carrying values of all other financial assets and liabilities approximate their fair values.

Financial Risks

During the normal course of business, Manitoba Hydro is exposed to a number of financial risks including credit and liquidity risks and market risk resulting from fluctuations in foreign currency, interest rates and commodity prices. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by the corporation and its subsidiaries, to set risk tolerance limits, establish controls and to monitor risk and adherence to policies. An integrated risk management plan has been developed and reviewed by the Manitoba Hydro-Electric Board to ensure the adequacy of the risk management framework in relation to the risks faced by the corporation. The nature of the financial risks and Manitoba Hydro's strategy for managing these risks has not changed significantly from the prior year.

a) Credit Risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Manitoba Hydro is exposed to credit risk related to sinking fund investments, short-term investments and pension fund investments. The corporation limits its exposure to credit risk by only investing in government-guaranteed bonds, highly rated investments and well-diversified investment portfolios.

The corporation is also exposed to credit risk related to domestic and export energy sales. Credit risk related to domestic sales is mitigated by the large and diversified electric and gas customer base. Credit risk in the export power market is mitigated by establishing credit requirements, conducting standard credit reviews of all counterparties and setting and monitoring exposure limits for each of these counterparties. Letters of credit and netting provisions are also in place to further mitigate credit risk. The maximum exposure to credit risk related to domestic and export energy sales is its fair value.

The value of the corporation's aged accounts receivable and related bad debt provisions are presented in the following table:

	Manitoba	Extraprovincial	2014 Total	2013 Total
		millions of dollars		
Under 30 days	370	41	411	342
31 to 60 days	25	-	25	25
61 to 90 days	9	-	9	8
Over 90 days	27	-	27	26
	431	41	472	401
Provision at end of year	(9)	-	(9)	(9)
Total accounts receivable	422	41	463	392

The provision for bad and doubtful accounts is reviewed annually, based on an estimate of aged receivables that are considered uncollectible.

b) Liquidity Risk

Liquidity risk refers to the risk that Manitoba Hydro will not be able to meet its financial obligations as they come due. The corporation meets its financial obligations when due through cash generated from operations, short-term borrowings, long-term borrowings advanced from the Province of Manitoba and sinking fund withdrawals.

The following is an analysis of the contractual undiscounted cash flows payable under financial liabilities and derivative liabilities as at the consolidated balance sheet date:

	Carrying value	2015	2016	2017	2018	2019	2020 and thereafter
				millions of dollars			
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	561	561	-	-	-	-	-
Asset purchase obligation	207	16	16	16	16	16	16*
Long-term debt**	10 968	1 067	977	975	994	1 942	15 725
		1 644	993	991	1 010	1 958	15 741
Derivative financial liabilities							
Commodity derivatives							
Fixed price swap contracts	-	-	-	-	-	-	-
		-	-	-	-	-	-
		1 644	993	991	1 010	1 958	15 741

*per year in perpetuity
**including current portion and interest payments

c) Market Risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Manitoba Hydro is exposed to three types of market risk: foreign exchange risk, interest rate risk and commodity price risk associated with the price of electricity and natural gas. Manitoba Hydro continually monitors its exposure to these risks and may use hedges or derivative contracts to manage these risks.

i. Foreign Exchange Risk

Manitoba Hydro has exposure to U.S. dollar foreign exchange rate fluctuations primarily through the sale and purchase of electricity in the U.S. and through borrowing in U.S. markets. This exposure is managed through a long-term natural hedge between U.S. dollar cash inflows from export revenues and U.S. dollar cash outflows for long-term coupon and principal payments.

To mitigate annual net income impacts due to foreign exchange rate fluctuations, long-term cash flow hedges have been established between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. Accordingly, translation gains and losses for U.S. long-term debt obligations in effective hedging relationships with future export revenues, are recognized in other comprehensive income until future hedged U.S. export revenues are realized, at which time the associated gains or losses in accumulated other comprehensive income are recognized in net income. For the year ended March 31, 2014, unrealized foreign exchange translation losses of $155 million (2013 - $31 million losses) were recognized in other comprehensive income and $19 million net gains (2013 - $2 million losses) were reclassified from other comprehensive income into net income.

Manitoba Hydro also has a fair value hedging relationship between U.S. long-term debt balances and U.S. sinking fund investments. Offsetting foreign exchange translation gains and losses on these items are recognized in net income.

In addition to natural hedging relationships, cross currency swap arrangements transacted by the Province of Manitoba on the corporation's behalf are utilized to manage exchange rate exposures and as a means to capitalize on favourable financing terms in either U.S. or Canadian capital markets. Cross currency agreements represent an exchange of principal and/or interest flows denominated in one currency for principal and/or interest flows denominated in another. Such transactions effectively amend the terms of the original debt obligation with the Province of Manitoba with the swapped debt arrangement.

As at March 31, 2014, a change in the Canadian dollar of plus (minus) $0.10 relative to the U.S. dollar would decrease (increase) net income by $0.6 million (2013 - $0.4 million), while other comprehensive income would increase (decrease) by $160 million (2013 - $177 million).

ii. Interest Rate Risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. Manitoba Hydro is exposed to interest rate risk associated with temporary investments, floating rate long-term debt and fixed rate long-term debt maturing within 12 months, less sinking fund withdrawals, offset by the change in interest capitalization. As at March

31, 2014, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $15 million (2013 - $15 million), with no impact to other comprehensive income.

Interest rate swap agreements transacted by the Province of Manitoba on the corporation's behalf are utilized to manage the fixed and floating interest rate mix of the total debt portfolio, interest rate exposure and related overall cost of borrowing. Interest rate swap agreements represent an agreement between two parties to periodically exchange payments of interest without the exchange of the principal amount upon which payments are based. The Province of Manitoba may also enter into forward start interest rate swap arrangements where the agreement to exchange interest payments commences at some future date. In either swap arrangement, the terms of the debt advanced by the Province of Manitoba to the corporation are amended by the swap.

iii. Commodity Price Risk

The corporation is exposed to electricity price risk that results from volatility of market prices and natural gas price risk through its purchase of gas for delivery to customers throughout Manitoba. The corporation mitigates commodity price risk through its limited use of derivative financial instruments restricted to contracts for differences, forward power sales contracts and natural gas price swaps. Manitoba Hydro does not use derivative contracts for trading or speculative purposes.

The corporation has entered into forward power sales contracts for 50 400 megawatt hours of electricity until June 2014 and natural gas price swaps until July 2016 to purchase 87 450 gigajoules of natural gas. These contracts are reported as derivatives and carried at fair value on the consolidated balance sheet. The unrealized fair value gains of financial derivative contracts as at March 31 are as follows:

	2014	2013
	millions of dollars	
Commodity derivative contracts	2	-

Fair values of forward sales contracts are calculated using the monthly forward electricity prices at pricing points specified in the contracts. Fair values of price swaps are calculated using the monthly forward AECO price as reported by the Natural Gas Exchange as at March 31, 2014.

NOTE 20 CAPITAL MANAGEMENT

Manitoba Hydro manages its capital structure to ensure that there is sufficient equity to absorb the financial effects of adverse circumstances and to ensure continued access to stable low-cost funding for capital projects and ongoing operational requirements.

The corporation monitors its capital structure on the basis of its equity ratio. Manitoba Hydro's long-term target is to achieve a minimum equity ratio of 25%. It is recognized that the equity ratio target may not be achieved during years of major investment in the generation and transmission system.

The corporation's equity ratio as at March 31 was as follows:

	2014	2013
	dollars are in millions	
Long-term debt, net of sinking fund investments	10 349	8 977
Current portion, long-term debt	408	656
Less: Cash and cash equivalents	(142)	(32)
Net debt	10 615	9 601
Retained earnings	2 716	2 542
Accumulated other comprehensive income	96	299
Contributions in aid of construction	381	340
Non-controlling interest	73	95
Total equity	3 266	3 276
Equity ratio	24%	25%

Manitoba Hydro issues debt for its capital requirements under the authority of *The Manitoba Hydro Act* and *The Loan Act*. *The Manitoba Hydro Act* grants the corporation the power to issue up to $500 million of short-term promissory notes. Manitoba Hydro submits annual requests under *The Loan Act* for the necessary borrowing authority for new capital requirements and the refinancing of any maturing long-term debt. The majority of Manitoba Hydro's long-term debt is obtained through advances by the Province of Manitoba.

NOTE 21 EMPLOYEE FUTURE BENEFITS

Manitoba Hydro employees are eligible for pension benefits under the CSSB defined benefit plan that provides pension benefits based on years of service and on the average earnings of the five best years. The CSSB plan requires the corporation to contribute approximately 50% of the pension disbursements made to retired employees. All current employees participating in the CSSB plan are eligible for enhanced pension benefits under the EHBP. The EHBP improves the pension formula used to calculate pension for active service accrued after June 1, 2006. In addition, the former employees of Centra are entitled to pension benefits earned under the Centra curtailed pension plans. The former Winnipeg Hydro employees continue to earn benefits under the WCEBP in which, upon the acquisition of Winnipeg Hydro, Manitoba Hydro became a participating employer. The WCEBP is also a defined benefit plan that provides pension benefits based on years of service and on the average earnings of the five best years.

The CSSB manages the corporation's pension funds (MH Pension Fund and EHBP) on behalf of the corporation. The assets related to the Centra curtailed pension plans are held in trust by State Street Trust Co. of Canada. The assets and liabilities of the WCEBP are not reflected on Manitoba Hydro's consolidated balance sheet.

MHUS employees are eligible for pension benefits under the CSSB defined benefit plan. As a matching employer under the Civil Service Superannuation Act, MHUS is required to match employee contributions at a prescribed rate into the Civil Service Superannuation Fund (CSSF) pool of assets. MHUS' pension expense is recognized at the time contributions are made to the fund. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements related to the MHUS defined benefit plan.

MHI sponsors a defined contribution group registered retirement plan. MHI matches 100% of the employee contributions at prescribed contribution rates. The cost of the pension benefits is charged to pension expense as services are rendered. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements for the MHI defined contribution plan.

The following table presents information pertaining to the MH Pension Fund, the EHBP and the Centra curtailed pension plans:

	MH Pension Fund		Enhanced Hydro Benefit Plan		Centra curtailed plans		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
	millions of dollars							
Plan assets at fair value								
Balance at beginning of year	792	758	14	11	97	84	903	853
Actual return on plan assets	108	52	1	1	13	6	122	59
Employer contributions	30	26	2	2	10	12	42	40
Benefit payments and refunds	(47)	(44)	-	-	(5)	(5)	(52)	(49)
	883	792	17	14	115	97	1 015	903
Accrued benefit obligation								
Balance at beginning of year	1 232	1 012	20	11	113	98	1 365	1 121
Interest on obligation	52	53	1	1	5	5	58	59
Current service cost	45	35	2	2	-	-	47	37
Benefit payments and refunds	(47)	(45)	-	-	(5)	(5)	(52)	(50)
Actuarial (gains) losses	(17)	177	(1)	6	(2)	15	(20)	198
	1 265	1 232	22	20	111	113	1 398	1 365
Surplus (deficit) at end of year	(382)	(440)	(5)	(6)	4	(16)	(383)	(462)
Unamortized past service costs	-	-	-	-	-	1	-	1
Unamortized transitional balance	-	(1)	-	-	-	-	-	(1)
Unamortized net actuarial loss	424	521	4	6	45	57	473	584
Accrued benefit asset (obligation)	42	80	(1)	-	49	42	90	122

Pension assets are valued at market rates and are invested as follows:

	MH Pension Fund fair value		Centra curtailed pension plans fair value	
	2014	2013	2014	2013
	millions of dollars			
Equities	578	492	75	63
Bonds and debentures	174	185	23	23
Real estate	87	89	11	8
Infrastructure	24	22	3	3
Short-term investments	20	4	3	-
	883	792	115	97

Manitoba Hydro has $18 million (2013 - $14 million) on deposit with the CSSB for the EHBP. Manitoba Hydro does not have a separate portfolio of assets for the EHBP. The investment income earned on the EHBP funds is based on the market value rate of return that is earned by the CSSF. For the year ended December 31, 2013, the CSSF earned a rate of return of 14.7% (2013 – 10.2%) on fund assets.

The return on pension fund assets for the MH Pension Fund was 13.8% (2013 – 7.5%). The return for the Centra curtailed plan fund assets was 13.8% (2013 – 7.3%). The weighted average term to maturity on fixed income investments is 9.3 years (2013 – 8.9 years).

The most recent actuarial valuations for the corporation's obligations under the CSSB and Centra curtailed pension plans were performed with respect to the liabilities outstanding as at December 31, 2013. These valuations incorporated management's best estimate assumptions and took into consideration the long-term nature of the pension plans. The next actuarial valuations for all plans, including the EHBP will occur in December 2014. The Centra curtailed pension plans are also subject to a solvency valuation for funding purposes with the latest valuation taking place as at December 31, 2013.

The significant actuarial assumptions adopted in measuring the corporation's pension and other employee benefit obligations are as follows:

	2014	2013
Discount rate - pensions	4.50%	4.25%
Discount rate - other benefits	4.50%	4.25%
Expected long-term rate of return on plan assets	7.0%	7.0%
Rate of compensation increase, including merit and promotions	1.5 - 2.0%	1.5 - 2.0%
Expected average remaining service life of employees - MH Pensions	13 years	14 years
Expected average remaining service life of employees - Centra Pensions	10 years	10 years
Long-term inflation rate	2.0%	2.0%

The corporation's pension expense related to each of the pension benefit plans is as follows:

	CSSB Plan		Enhanced Hydro Benefit Plan		Centra curtailed pension plans	
	2014	2013	2014	2013	2014	2013
			millions of dollars			
Current service cost	45	35	2	2	-	-
Administrative fees	3	2	-	-	-	-
Canada Pension Plan	16	15	-	-	-	-
Interest on obligation	52	53	1	1	5	5
Expected return on plan assets	(59)	(58)	(1)	(1)	(7)	(7)
Amortization of net experience loss	28	13	-	-	4	2
Amortization of transitional gain	(1)	(1)	-	-	-	-
	84	59	2	2	2	-

Pension expense for the former Winnipeg Hydro employees is equal to employer contributions to the WCEBP in addition to employer remittances to the Canada Pension Plan. Total contributions to the WCEBP during the year amounted to $1 million (2013 - $1 million) and reflect an employer contribution rate approximating 4.3% of pensionable earnings to January 1, 2014 and 4.8% of pensionable earnings thereafter. Pension expense for MHUS and MHI is equal to the employer contributions and is expensed during the year. The amounts are not material.

Manitoba Hydro also provides some non-pension employee future benefits including banked incidental and vacation days, long-term disability, retiree health spending, sick leave vesting and severance.

The following table presents information concerning other employee future benefits:

	2014	2013
	millions of dollars	
Accrued benefit liability		
Balance at beginning of year	201	173
Interest on obligation	4	9
Current service cost	20	23
Benefit payments	(17)	(17)
Actuarial (gain) loss	(5)	13
	203	201
Unamortized past service costs	(6)	(7)
Unamortized transitional obligation	(2)	(3)
Unamortized net actuarial loss	(7)	(17)
Accrued benefit liability	188	174

NOTE 22 COMMITMENTS AND CONTINGENCIES

Manitoba Hydro has energy purchase commitments of $1 571 million (2013 - $1 592 million) that relate to future purchases of wind, natural gas (including transportation and storage contracts), coal and electricity. Commitments are primarily for wind, which expire in 2038, and natural gas purchases, which expire in 2020. In addition, other outstanding commitments principally for construction, are approximately $2 676 million (2013 - $1 592 million).

The corporation will incur future costs associated with the assessment and remediation of contaminated lands and facilities and for the phase-out and destruction of polychlorinated biphenyl contaminated mineral oil from electrical equipment. Although these costs cannot be reasonably determined at this time (except for items already recognized as asset retirement obligations), a contingent liability exists.

Due to the size, complexity and nature of Manitoba Hydro's operations, various legal and operational matters are pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have an adverse effect on Manitoba Hydro's consolidated financial position or results of operations.

Manitoba Hydro provides guarantees to counterparties as part of its use of natural gas derivative commodity contracts. Guarantees issued at March 31, 2014 totaled $311 million (2013 - $289 million) and do not have specific maturity dates. Letters of credit in the amount of $7 million (2013 - $6 million) have been issued for energy related transactions with maturities until 2015.

NOTE 23 MITIGATION

Manitoba Hydro's mitigation program addresses past, present and ongoing adverse effects of historical hydro-electric development. The mitigation program, established in the late 1970s to address project impacts through alleviation of adverse effects, remedial works, offsetting programs, and residual monetary compensation, grew out of the experience of planning and development of the Lake Winnipeg Regulation and Churchill River Diversion Projects. The Northern Flood Agreement, signed December 16, 1977, created a process that addressed ongoing mitigation and compensation for adverse effects of hydro-electric development in five signatory First Nation communities (Nelson House, Split Lake, York Landing, Norway House, and Cross Lake). The mitigation program continues to address impacts arising from past hydro-electric developments, particularly for Aboriginal people residing or engaged in resource harvesting in the project areas, and it is essential for operating and future development purposes.

Expenditures recorded or settlements reached to mitigate the impacts of all projects amounted to $17 million during the year (2013 - $21 million). In recognition of future anticipated mitigation payments, the corporation has recorded a liability of $229 million (2013 - $235 million). To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.

Included in mitigation payments or liabilities are obligations assumed on behalf of the Province of Manitoba with respect to certain northern development projects. The corporation has assumed obligations totaling

$146 million for which water power rental charges were fixed until March 31, 2001. The obligations outstanding at March 31, 2014 amounted to $11 million (2013 - $11 million).

NOTE 24 AFFORDABLE ENERGY FUND

In accordance with the provisions of the Winter Heating Cost Control Act, Manitoba Hydro established an Affordable Energy Fund (the Fund) in the initial amount of $35 million for the purpose of providing support for programs and services that:

(a) encourage energy efficiency and conservation;
(b) encourage the use of alternative energy sources, including earth energy; and
(c) facilitate research and development of alternative energy services and innovative energy technologies.

For accounting purposes, the Fund is classified as other long-term assets (Note 14) with an offsetting balance in other long-term liabilities (Note 17). Expenditures of $4 million (2013 - $5 million) during the year were charged to operations with the asset and liability accounts reduced accordingly. As at March 31, 2014, the balance remaining in the Fund amounted to $11 million (2013 - $15 million).

NOTE 25 NON-CONTROLLING INTEREST

Manitoba Hydro has entered into a partnership agreement with Taskinigahp Power Corporation (TPC) to carry on the business of developing, owning and operating the Wuskwatim Generating Station. TPC is owned beneficially by Nisichawayasihk Cree Nation (NCN). The generating station and associated transmission was placed into service during the 2012-13 year.

The 33% ownership interest of TPC in the WPLP of $73 million (2013 - $95 million) is represented as a non-controlling interest within the equity section of the consolidated balance sheet. TPC's portion of the net loss of the WPLP during 2013-14 is $22 million (2013 – $13 million) and is recorded as non-controlling interest in the consolidated statement of income.

In accordance with the partnership agreements, Manitoba Hydro provides debt financing to TPC. As at March 31, 2014, Manitoba Hydro has provided advances to TPC of $92 million (2013 - $91 million). The advances plus interest are repayable by TPC through distributions from the WPLP.

NOTE 26 SEGMENTED INFORMATION

The corporation operates primarily in two business segments: electricity and gas. Each segment has its own particular economic characteristics and differs in nature, production processes and technology. The electricity segment encompasses the generation, transmission and distribution of electricity as well as subsidiaries providing related energy services. The gas segment represents natural gas supply and distribution activities through the operations of Centra. The corporate segment represents the costs to acquire Centra and to integrate its operations into those of Manitoba Hydro. These costs are allocated to gas and electricity segments in accordance with the synergies and benefits derived by each of these segments as a result of the acquisition.

The following table contains information related to the operating results, assets, liabilities, contributions in aid of construction and retained earnings by segment:

	Electricity		Gas		Corporate		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
				millions of dollars				
Revenues [1]	1 914	1 763	163	147	-	-	2 077	1 910
Expenses								
Operating and administrative	490	469	67	64	-	-	557	533
Finance expense	436	452	16	18	19	19	471	489
Depreciation and amortization	412	394	28	27	2	2	442	423
Water rentals and assessments	125	118	-	-	-	-	125	118
Fuel and power purchased	177	133	-	-	-	-	177	133
Capital and other taxes	97	87	20	18	-	-	117	105
Other expenses	36	30	-	-	-	-	36	30
Corporate allocation	9	9	12	12	(21)	(21)	-	-
	1 782	1 692	143	139	-	-	1 925	1 831
Net income before non-controlling interest	132	71	20	8	-	-	152	79
Net loss attributable to non-controlling interest	22	13	-	-	-	-	22	13
Net income	154	84	20	8	-	-	174	92
Total assets	14 950	13 928	689	614	-	-	15 639	14 542
Total liabilities	11 909	10 848	464	418	-	-	12 373	11 266
Contributions in aid of construction	339	307	42	33	-	-	381	340
Retained earnings	2 654	2 500	62	42	-	-	2 716	2 542

[1]Revenues are stated net of cost of gas sold of $252 million (2013 - $182 million).

NOTE 27 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2013 have been reclassified in order to conform to the presentation adopted in 2014.

Installing energy efficient LED street lights in Brandon.

Financial statistics

For the year ended March 31	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
					dollars are in millions					
Revenues										
Electrical:										
Residential	606	563	492	503	476	463	436	410	387	386
General service	799	778	701	697	669	664	638	614	597	553
Extraprovincial	439	353	363	398	427	623	625	592	827	554
Other revenue	70	69	45	41	27	34	23	16	17	15
Gas:										
Residential	208	174	172	205	222	292	268	258	245	244
Commercial / Industrial	201	149	151	193	225	281	254	244	267	258
Transportation	4	5	5	5	5	5	4	4	3	5
Other revenue	2	1	1	1	2	2	2	2	2	2
	2 329	2 092	1 930	2 043	2 053	2 364	2 250	2 140	2 345	2 017
Expenses										
Operating and administrative	557	533	481	463	440	429	381	381	368	357
Finance expense	471	489	423	425	410	471	440	506	503	502
Depreciation and amortization	442	423	381	393	384	368	349	332	322	311
Water rentals and assessments	125	118	119	120	121	123	124	112	131	111
Fuel and power purchased	177	133	146	106	104	176	134	226	125	135
Capital and other taxes	117	105	103	102	99	87	80	77	77	75
Cost of gas sold	252	182	197	261	316	431	386	379	397	384
Other expenses	36	30	19	23	16	13	10	5	7	6
	2 177	2 013	1 869	1 893	1 890	2 098	1 904	2 018	1 930	1 881
Net income before non-controlling interest	152	79	61	150	163	266	346	122	415	136
Net loss attributable to non-controlling interest	22	13	-	-	-	-	-	-	-	-
Net Income	174	92	61	150	163	266	346	122	415	136
Assets										
Property, plant and equipment	16 190	15 793	13 631	12 967	12 688	12 300	11 884	11 424	11 065	10 748
Less: Accumulated depreciation	5 506	5 252	4 984	4 752	4 612	4 356	4 187	3 924	3 657	3 447
Construction in progress	2 943	1 967	3 150	2 739	2 052	1 438	1 238	878	602	475
Sinking fund investments	111	352	372	282	822	666	718	630	555	562
Current and other assets	1 901	1 682	1 622	1 646	1 487	1 499	2 113	1 914	1 917	1 614
	15 639	14 542	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952
Liabilities and Equity										
Long-term debt	10 460	9 329	9 101	8 617	8 228	7 668	7 218	6 822	7 051	7 048
Current and other liabilities	1 913	1 937	1 495	1 127	1 328	1 637	2 097	2 380	1 849	1 738
Contributions in aid of construction	381	340	318	295	295	296	300	298	297	296
Non-controlling interest	73	95	100	87	62	39	24	15	-	-
Retained earnings	2 716	2 542	2 450	2 389	2 239	2 076	1 822	1 407	1 285	870
Accumulated other comprehensive income	96	299	327	367	285	(169)	305	-	-	-
	15 639	14 542	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952
Cash Flows										
Operating activities	690	589	567	595	589	688	633	443	710	433
Financing activities	1 101	635	725	674	1 124	424	487	227	77	236
Investing activities	1 681	1 242	1 312	1 373	1 698	1 086	988	788	677	666
Financial Indicators										
Equity ratio[1]	24%	25%	26%	27%	27%	23%	27%	20%	19%	15%
Interest coverage[2]	1.28	1.15	1.10	1.27	1.32	1.49	1.69	1.23	1.77	1.25
Capital coverage[3]	1.35	1.25	1.13	1.25	1.34	1.77	1.62	1.10	2.28	1.20

[1] Equity ratio represents equity (retained earnings plus accumulated other comprehensive income plus contributions in aid of construction plus non-controlling interest) divided by equity plus debt (long-term debt plus notes payable minus sinking fund investments and temporary investments).

[2] Interest coverage represents net income plus interest on debt divided by interest on debt.

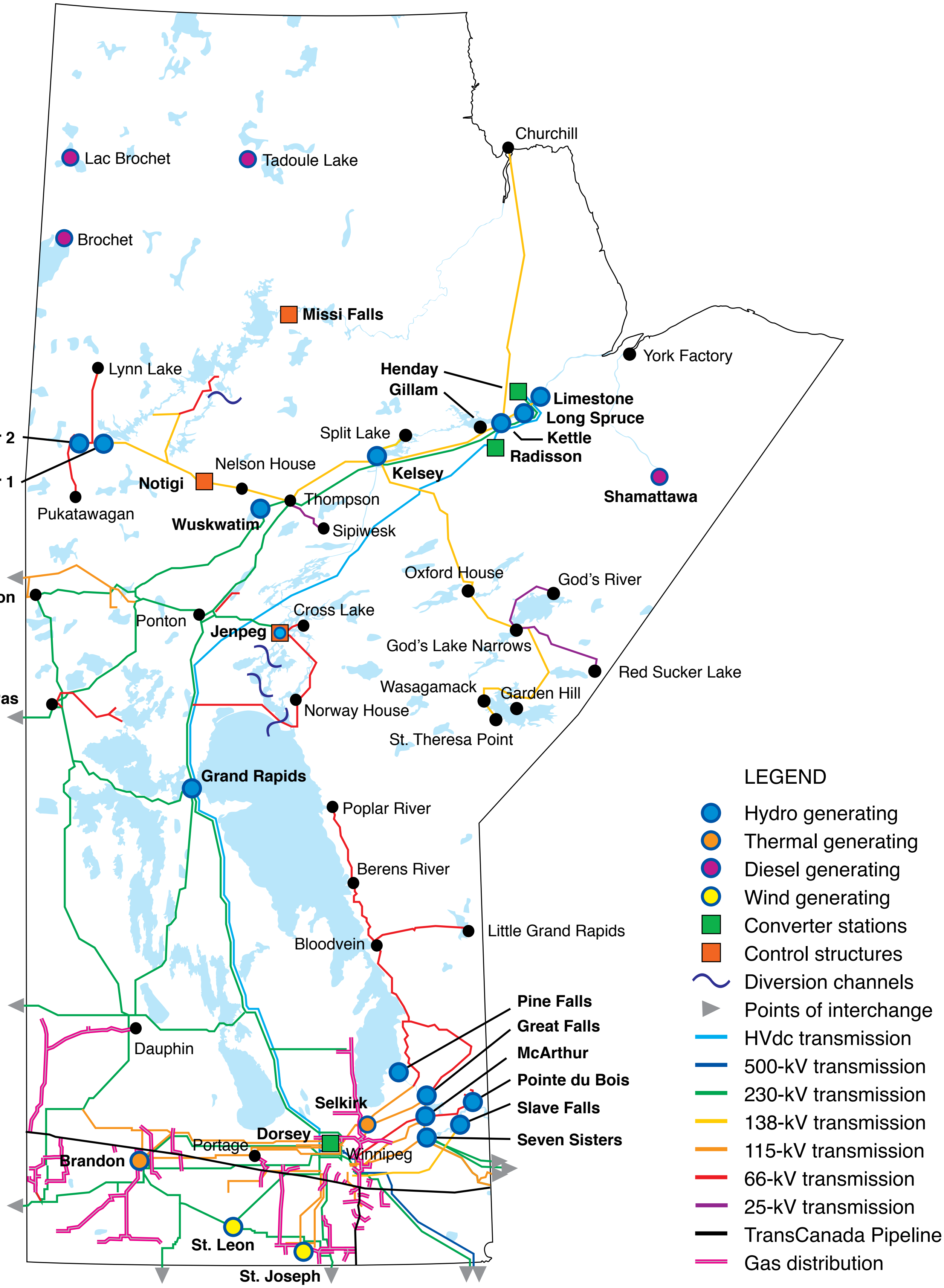
[3] Capital coverage represents internally generated funds divided by capital construction expenditures.

Operating statistics

For the year ended March 31	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
Electric System Capability										
Capability (000 kW)	5 715	5 675	5 475	5 489	5 501	5 480	5 465	5 461	5 469	5 470
Manitoba firm peak demand (000 kW)	4 720	4 535	4 343	4 261	4 359	4 477	4 273	4 184	4 054	4 169
Percent change	4.1	4.4	1.9	(2.2)	(2.6)	4.8	2.1	3.2	(2.8)	5.3
Electric System Supply										
Total energy supplied (millions of kWh)										
Generation	35 392	33 230	33 235	34 102	33 961	34 528	35 354	32 132	37 620	31 548
Isolated systems	14	14	14	13	13	13	12	12	12	11
	35 406	33 244	33 249	34 115	33 974	34 541	35 366	32 144	37 632	31 559
Electric Load at Generation (millions of kWh)										
Integrated system	25 510	24 650	23 499	23 783	23 295	24 285	23 985	23 327	22 622	22 452
Isolated system	14	14	14	13	13	13	12	12	12	11
	25 524	24 664	23 513	23 796	23 308	24 298	23 997	23 339	22 634	22 463
Percent change	3.5	4.9	(1.2)	2.1	(4.1)	1.3	2.8	3.1	0.8	2.5
Electric System Deliveries (millions of kWh)										
Energy delivered in Manitoba										
Residential	7 889	7 334	6 930	7 060	6 899	6 954	6 838	6 539	6 266	6 370
General service	14 467	14 143	13 840	13 727	13 587	14 256	14 223	13 965	13 669	13 365
	22 356	21 477	20 770	20 787	20 486	21 210	21 061	20 504	19 935	19 735
Extraprovincial	10 537	9 087	10 244	10 344	10 860	10 122	11 086	10 100	13 773	10 475
	32 893	30 564	31 014	31 131	31 346	31 332	32 147	30 604	33 708	30 210
Gas Deliveries (millions of cubic metres)										
Residential	664	602	509	591	581	696	682	653	600	681
Commercial / Industrial	964	849	728	821	803	866	856	811	782	917
Transportation	652	598	629	584	619	603	618	592	598	559
	2 280	2 049	1 866	1 996	2 003	2 165	2 156	2 056	1 980	2 157
Number of Customers										
Electric:										
Residential	486 654	480 254	474 661	469 635	465 055	460 804	455 430	450 823	446 370	442 840
General service	69 106	68 520	68 020	67 664	67 304	66 668	66 169	66 038	63 421	62 826
	555 760	548 774	542 681	537 299	532 359	527 472	521 599	516 861	509 791	505 666
Gas:										
Residential	247 010	244 768	242 813	241 123	239 535	239 597	237 724	236 086	234 108	231 366
Commercial / Industrial	25 218	25 018	24 886	24 838	24 766	23 411	23 435	23 483	23 709	24 559
	272 228	269 786	267 699	265 961	264 301	263 008	261 159	259 569	257 817	255 925
Full Time Equivalent (FTE) [1]	6 556	6 463	6 413	6 394	6 236	6 080	5 841	5 773	5 748	5 682

[1] Regular FTEs (the straight time hours of work for one employee) for Manitoba Hydro, including subsidiaries.

Major electrical and gas facilities



Sources of Electrical Energy Generated and Purchased

For the Year Ended March 31, 2014

Nelson River	**73.63 %**
Billion kWh generated	**27.1**
Limestone	23.89 %
Kettle	23.03 %
Long Spruce	19.23 %
Kelsey	5.82 %
Jenpeg	1.66 %
Winnipeg River	**10.95 %**
Billion kWh generated	**4.0**
Seven Sisters	3.15 %
Great Falls	2.76 %
Pine Falls	1.59 %
Pointe du Bois	1.01 %
Slave Falls	1.23 %
McArthur	1.21 %

Saskatchewan River	**6.69 %**
Billion kWh generated	**2.5**
Grand Rapids	6.69 %
Laurie River	**0.08 %**
Billion kWh generated	**0.0**
Laurie River 1	0.04 %
Laurie River 2	0.04 %
Burntwood River	**4.03 %**
Billion kWh generated	**1.5**
Wuskwatim	4.03 %

Thermal	**0.35 %**
Billion kWh generated	**0.1**
Brandon	0.32 %
Selkirk	0.04 %
Purchases (excl. wind)	**1.74 %**
Billion kWh purchased	**0.6**
Wind	**2.52 %**
Billion kWh purchased	**0.9**

Manitoba Hydro Generating Stations and Capabilities

For the Year Ended March 31, 2014

Interconnected Capabilities

Station	Location	Number of units	Net Capability (MW)
Hydraulic			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	87
McArthur	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	67
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	292
Kettle	Nelson River	12	1220
Jenpeg	Nelson River	6	125
Long Spruce	Nelson River	10	980
Limestone	Nelson River	10	1350
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	214
Thermal			
Brandon		3	342
Selkirk		2	125

Isolated Capabilities

Diesel	
Brochet	3
Lac Brochet	2
Shamattawa	3
Tadoule Lake	2
Total Generating Capability	5 725

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The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the three months ended June 30, 2014

Comments by

THE CHAIR OF THE BOARD

and by

THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro's consolidated net income from electricity and natural gas operations was $7 million for the first three months of the 2014-15 fiscal year compared to a net loss of $5 million for the same period last year. The improved financial performance was primarily attributable to increased domestic sales revenues due to an increase in electricity rates and lower expenses.

Consolidated net income was comprised of a $14 million profit in the electricity sector and a $7 million loss in the natural gas sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and is expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $60 million by March 31, 2015.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $329 million for the three-month period, which was $7 million or 2% higher than same period last year. The increase in domestic revenue was attributable to electricity rate increases. Extraprovincial revenues of $111 million were $3 million or 3% lower than the same period last year reflecting lower sales volumes as a result of a U.S. transmission line outage, partially offset by favourable foreign exchange rates on U.S. sales. Energy sold in the export market was 2.9 billion kilowatt-hours compared to 3.1 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $432 million for the three-month period, a decrease of $7 million or 2% lower than the same period last year. The decrease was the net result of a $3 million reduction in operating and administrative costs, a $3 million decrease in other expenses, a $2 million decrease in finance expense, a $1 million decrease in water rentals and assessments, a $1 million decrease in fuel and power purchased costs, partially offset by a $1 million increase in depreciation and amortization expense and a $1 million increase in capital and other taxes.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first three months of the 2014-15 fiscal year.

Capital expenditures for the three-month period amounted to $379 million compared to $277 million for the same period last year. Expenditures during the current period included $136 million related to future Keeyask and Conawapa generation, $55 million for Bipole III projects, $52 million for Pointe du Bois projects, $11 million for Riel Station, and $6 million for demand-side management programs. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province.

Natural Gas Operations

In the natural gas sector, a net loss of $7 million was incurred for the three-month period, which is the same as the comparable period last year. Revenue, net of cost of gas sold, was $29 million, which is identical to the same period last year. Delivered gas volumes were 379 million cubic metres compared to 400 million cubic metres in the prior period.

Expenses attributable to natural gas operations amounted to $36 million compared, which is the same as the comparable period last year.

Capital expenditures in the natural gas sector were $8 million for the current three-month period compared to $10 million for the same period last year. Capital expenditures included $6 million related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province and $2 million related to demand-side management programs.

Keeyask Generation Project Approved

In May 2014 the Minister of Conversation and Water Stewardship released the Manitoba Clean Environment Commission's (CEC) report on the Keeyask Generation Project, which recommended the project be issued a license under the Manitoba Environment Act. The CEC report made a number of licensing and non-licensing recommendations for the construction and operation of the project.

The Province of Manitoba issued an Environment Act License for Keeyask and released the Public Utilities Board Panel report on the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Development Plan on July 2, 2014. The NFAT review panel recommended proceeding with immediate construction of Keeyask to meet domestic and export requirements as well as a new transmission interconnection to the United States, which will enhance export capability, drought support and reliability.

On July 5, 2014 the Province approved an Interim Water Power Act License for Keeyask. The Department of Fisheries and Oceans granted Fisheries Act Authorization on July 15, 2014. Following receipt of all required approvals, construction began on the Keeyask Generating Station on July 16, 2014.

The $6.5 billion, 695-megawatt Keeyask Generating station is being developed by Manitoba Hydro in partnership with four Manitoba First Nations — Tataskweyak Cree Nation, War Lake First Nation, Fox Lake First Nation and York Factory First Nation. The generating station will be located on the Nelson River approximately 30 kilometres west of Gillam, within the Split Lake Resource Management Area. The first generator unit in-service date is targeted for 2019 with all units being commissioned by 2020.

Electricity Rate Increase

Electricity rates for all customer classes increased by approximately 2.75% effective May 1, 2014. The Public Utilities Board directed that 2.0% of the 2.75% increase be included in general revenues and that 0.75% of the increase be used to mitigate rate increases when Bipole III comes into service.

The rate increase was necessary to provide sufficient revenues for the corporation to meet its ongoing cost of operations and support ongoing reliability of electricity service. Even with the rate increase, electricity customers in Manitoba continue to benefit from one of the lowest electricity rate structures in North America.

Natural Gas Rate Increase

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers increased on May 1, 2014 by 4.6% or approximately $38 per year. Rate increases for larger volume customers ranged from 5.3% to 9.4% depending on the customer class and consumption levels.

William Fraser, FCA
Chair of the Board

Scott Thomson, CA
President and
Chief Executive Officer
August 15, 2014

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30 2014	2013
Revenues		
Electric – Manitoba	329	322
– Extraprovincial	111	114
Gas – Commodity	40	32
– Distribution	29	29
	509	497
Cost of gas sold	40	32
	469	465
Expenses		
Operating and administrative	132	135
Finance expense	123	125
Depreciation and amortization	112	110
Water rentals and assessments	29	30
Fuel and power purchased	36	37
Capital and other taxes	30	29
Other expenses	6	9
	468	475
Net Income (Loss) before non-controlling interest	1	(10)
Net Loss attributable to non-controlling interest	6	5
Net Income (Loss)	7	(5)

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at June 30 2014	*As at June 30* 2013
Assets		
Capital assets	13 922	12 707
Current assets	782	551
Other assets	1 154	1 120
	15 858	14 378
Liabilities and Equity		
Long-term debt (net)	10 800	8 936
Current liabilities	865	1 474
Other liabilities	854	773
Contributions in aid of construction	390	346
Non-controlling interest	67	90
Retained earnings	2 723	2 537
Accumulated other comprehensive income	159	222
	15 858	14 378

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2014	**2013**
Operating Activities		
Cash receipts from customers	639	574
Cash paid to suppliers and employees	(458)	(289)
Net interest	(147)	(150)
	34	135
Financing Activities	362	188
Investing Activities	(390)	(333)
Net increase (decrease) in cash	6	(10)
Cash at beginning of period	142	32
Cash at end of period	148	22

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2014	**2013**
Net Income (Loss)	7	(5)
Other Comprehensive Income (Loss)		
Unrealized foreign exchange gains (loss) on debt in cash flow hedges	62	(71)
Unrealized fair value losses on available-for-sale U.S. sinking fund investments	-	(6)
	62	(77)
Comprehensive Income (Loss)	69	(82)

Segmented Information

In Millions of Dollars (Unaudited)

Three Months Ended	**Electricity**		**Gas**		**Total**	
June 30	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Revenue (net of cost of gas sold)	440	436	29	29	469	465
Expenses	432	439	36	36	468	475
Net Income (Loss) before non-controlling interest	8	(3)	(7)	(7)	1	(10)
Net Loss attributable to non-controlling interest	6	5	-	-	6	5
Net Income (Loss)	14	2	(7)	(7)	7	(5)
Total Assets	15 180	13 778	678	600	15 858	14 378

Generation and Delivery Statistics

	Three Months Ended June 30	
	2014	**2013**
Electricity in gigawatt-hours		
Hydraulic generation	8 437	8 536
Thermal generation	5	24
Scheduled energy imports	28	38
Wind purchases (MB)	233	228
Total system supply	8 703	8 826
Gas in millions of cubic metres		
Gas sales	196	201
Gas transportation	183	199
	379	400

For further information contact:

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Cover: Manitoba Hydro crews helped with sandbag production and other flood fighting measures this past spring and summer across Manitoba.

The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the six months ended September 30, 2014

Comments by

THE CHAIR OF THE BOARD

and by

THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro incurred a net loss on consolidated electricity and natural gas operations of $6 million for the first six months of the 2014-15 fiscal year compared to a net loss of $2 million for the same period last year. The increase in net loss was primarily attributable to higher financing expenses partially offset by increased revenues from domestic electricity sales.

The consolidated net loss was comprised of a $22 million loss in the natural gas sector and a $16 million profit in the electricity sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and is expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions and assuming normal winter weather, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $100 million by March 31, 2015.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $612 million for the six-month period, which was $23 million or 4% higher than same period last year. The increase in domestic revenue was primarily attributable to electricity rate increases and an increase in customers. Extraprovincial revenues of $241 million were $1 million lower than the same period last year reflecting lower sales volumes as a result of a U.S. transmission line outage, mainly offset by favourable foreign exchange rates on U.S. sales. Energy sold in the export market was 6.6 billion kilowatt-hours compared to 7.1 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $879 million for the six-month period, an increase of $23 million or 3% higher than the same period last year. The increase was the result of a $29 million increase in finance expense, a $5 million increase in depreciation and amortization expense, a $2 million increase in capital and other taxes and a $1 million increase in fuel and power purchased costs, partially offset by a $10 million decrease in operating and administrative expenses, a $3 million decrease in other expenses and a $1 million decrease in water rental and assessments. Finance expense increased primarily as a result of realized foreign exchange gains on U.S. debt and gains on the sale of U.S. sinking fund investments that were recorded in the previous fiscal year. Depreciation and amortization expense increased primarily as a result of the Riel 230-kV station and the Pointe du Bois spillway coming into service in the current year. Operating and administrative expenses decreased due to a greater focus on capital requirements relating to new and existing infrastructure.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first six months of the 2014-15 fiscal year.

Capital expenditures for the six-month period amounted to $943 million compared to $634 million for the same period last year. Expenditures during the current period included $429 million related to future Keeyask generation, $115 million for Bipole III projects, $89 million for the Pointe du Bois projects, $23 million for future Conawapa generation and $20 million for the Riel Station. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The Corporation also incurred $13 million for electric demand-side management programs.

Natural Gas Operations

In the natural gas sector, a net loss of $22 million was incurred for the six-month period, compared to the net loss of $21 million in the same period last year. Revenue, net of cost of gas sold, was $50 million which is $1 million higher than the same period last year. The increase in net revenues was primarily related to a distribution rate increase implemented in the summer of 2013. Delivered gas volumes were 596 million cubic metres compared to 643 million cubic metres in the prior period.

Expenses attributable to natural gas operations amounted to $72 million as compared to $70 million for the same period last year. The increase was the result of a $1 million increase in operating and administrative expenses and a $1 million increase in depreciation and amortization expense.

Capital expenditures in the natural gas sector were $16 million for the current six-month period compared to $17 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The Corporation also incurred $4 million for gas demand-side management programs.

Construction Starts on the Keeyask Generating Station

Upon receiving all necessary approvals, construction on the Keeyask Generating Station commenced as scheduled on July 16, 2014. The general civil contract, the largest contract on the Keeyask project, was awarded to BBE Hydro Constructors Limited Partnership (BBE) on March 10, 2014, for a value of $1.4 billion. BBE is a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. BBE has begun to construct river management structures including the quarry cofferdam, north channel rock groin, north channel stage 1 cofferdam and the first portion of the powerhouse cofferdam in preparation for river diversion which will allow for construction of the generating station's principle structures.

The first phase of the Keeyask main camp is nearing completion and staff have begun to occupy some of the camp's 588 rooms. Over the next 18 months, the camp will be expanded to house approximately 2,000 workers which will be required for peak construction of the Keeyask Generating Station.

The $6.5 billion, 695-megawatt Keeyask Generating Station is being developed by Manitoba Hydro in partnership with four Manitoba First Nations — Tataskweyak Cree Nation, War Lake First Nation, Fox Lake First Nation and York Factory First Nation. The generating station will be located on the Nelson River approximately 30 kilometres west of Gillam, within the Split Lake Resource Management Area. The first generator unit in-service date is targeted for 2019 with all units being commissioned by 2020.

Supplier Selected for Largest Bipole III Reliability Project Contract

Manitoba Hydro has selected the supplier for the largest contract associated with the Bipole III reliability project. The consortium of Siemens Canada and Mortenson Canada was chosen to design, supply and install the High Voltage Direct Current (HVDC) equipment and buildings required for the project's two convertor stations which is valued at approximately $800 million. The signing of the contract is expected to take place in early October. With the majority of the contract costs now committed, the budget for the Bipole III project is $4.6 billion as compared to the preliminary estimate of $3.3 billion prepared in 2011.

The Bipole III project is the best option for enhancing the reliability of Manitoba Hydro's transmission system and reducing the dependencies on the Dorsey Converter Station and the existing HVDC Interlake corridor. It includes: a 1 384-kilometre, 500 kV direct current transmission line; the Keewatinohk Converter Station and the Riel Converter Station. These facilities will back-up the Bipole I and II HVDC transmission systems, which share a common right-of-way corridor, and the Dorsey Converter Station. Currently over 70 percent of all electricity generated by Manitoba Hydro travels south over two, side-by-side transmission lines, Bipoles I and II and being in such close proximity to each other make the lines susceptible to being impacted by a single weather incident or forest fire event, as happened in September 1996. Bipole III and other converter stations provide an alternate path for electricity to reach customers should such an event re-occur. The project also provides the additional capacity to bring electricity from the new hydro projects in the north to southern Manitoba and offers employment, training and other economic benefits for Manitoba.

Natural Gas Rate Changes

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers decreased on August 1, 2014 by 0.8% or approximately $7 per year. Rate changes for larger volume customers ranged from a decrease of 2.0% to an increase of 3.8% depending on the customer class and consumption levels.

William Fraser, FCA

Chair of the Board

Scott Thomson, CA

President and
Chief Executive Officer
November 15, 2014

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2014	**2013**	**2014**	**2013**
Revenues				
Electric – Manitoba	612	589	298	285
– Extraprovincial	241	242	130	128
– Other	29	33	14	15
Gas – Commodity	58	45	18	13
– Distribution	50	49	21	20
	990	958	481	461
Cost of gas sold	58	45	18	13
	932	913	463	448
Expenses				
Operating and administrative	264	273	132	138
Finance expense	258	229	135	104
Depreciation and amortization	228	222	116	112
Water rentals and assessments	62	63	33	33
Fuel and power purchased	66	65	30	28
Capital and other taxes	60	58	30	29
Other expenses	13	16	7	7
	951	926	483	451
Net Loss before non-controlling interest	(19)	(13)	(20)	(3)
Net Loss attributable to non-controlling interest	13	11	7	6
Net Income (Loss)	(6)	(2)	(13)	3

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at September 30	As at September 30
	2014	**2013**
Assets		
Capital assets	14 443	13 000
Current assets	847	516
Other assets	1 201	1 105
	16 491	14 621
Liabilities and Equity		
Long-term debt (net)	11 501	9 419
Current liabilities	728	1 205
Other liabilities	968	780
Contributions in aid of construction	402	355
Non-controlling interest	111	84
Retained earnings	2 710	2 540
Accumulated other comprehensive income	71	238
	16 491	14 621

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2014	**2013**	**2014**	**2013**
Operating Activities				
Cash receipts from customers	1 195	1 088	556	514
Cash paid to suppliers and employees	(656)	(503)	(198)	(214)
Net interest	(309)	(290)	(162)	(140)
	230	295	196	160
Financing Activities	885	512	523	324
Investing Activities	(950)	(781)	(560)	(448)
Net increase in cash	165	26	159	36
Cash at beginning of period	142	32	148	22
Cash at end of period	307	58	307	58

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2014	**2013**	**2014**	**2013**
Net Income (Loss)	(6)	(2)	(13)	3
Other Comprehensive Income (Loss)				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(26)	(25)	(88)	40
Realized foreign exchange (gains) losses on debt in cash flow hedges reclassified to income	-	(14)	-	(8)
Unrealized fair value losses on available-for-sale U.S. sinking fund investments	-	(9)	-	(3)
Realized gains on redemption of U.S. sinking fund investments	-	(13)	-	(13)
	(26)	(61)	(88)	16
Comprehensive Income (Loss)	(32)	(63)	(101)	19

Segmented Information

In Millions of Dollars (Unaudited)

Six Months Ended	**Electricity**		**Gas**		**Total**	
September 30	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Revenue (net of cost of gas sold)	882	864	50	49	932	913
Expenses	879	856	72	70	951	926
Net Income (Loss) before non-controlling interest	3	8	(22)	(21)	(19)	(13)
Net Loss attributable to non-controlling interest	13	11	-	-	13	11
Net Income (Loss)	16	19	(22)	(21)	(6)	(2)
Three Months Ended September 30						
Revenue (net of cost of gas sold)	442	428	21	20	463	448
Expenses	447	417	36	34	483	451
Net Income (Loss) before non-controlling interest	(5)	11	(15)	(14)	(20)	(3)
Net Income attributable to non-controlling interest	7	6	-	-	7	6
Net Income (Loss)	2	17	(15)	(14)	(13)	3
Total Assets	15 803	14 026	688	595	16 491	14 621

Generation and Delivery Statistics

	Six Months Ended September 30		*Three Months Ended September 30*	
	2014	**2013**	**2014**	**2013**
Electricity in gigawatt-hours				
Hydraulic generation	17 557	17 725	9 120	9 189
Thermal generation	16	44	11	20
Scheduled energy imports	39	77	11	39
Wind purchases (MB)	420	382	187	154
Total system supply	18 032	18 228	9 329	9 402
Gas in millions of cubic metres				
Gas sales	283	277	87	76
Gas transportation	313	366	130	167
	596	643	217	243

For further information contact:

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Manitoba Hydro

Cover: On August 23, 2014, the official in-service date of the new Pointe du Bois spillway, the first waters of the Winnipeg River pass through gate two.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

STATUS UPDATE REPORT as at October 31, 2014

Manitoba Hydro

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Executive Summary

Manitoba Hydro (MH) will be required to prepare financial statements in accordance with International Financial Reporting Standards (IFRS) effective for its 2015/16 fiscal year with comparative information presented for 2014/15. The 2015/16 transition year represents an additional one year deferral to MH's previous deferred transition date of 2014/15 and is the result of a February 2013 decision by the Accounting Standards Board of Canada (AcSB) to extend the option for rate-regulated entities to transition to IFRS to 2015. The AcSB provided for an additional deferral of transition in anticipation of an approval by the International Accounting Standards Board (IASB) of an interim standard permitting rate-regulated entities to continue to recognize rate regulated accounts for financial reporting upon transition to IFRS. On January 30, 2014, the IASB issued the interim standard IFRS 14 *Regulatory Deferral Accounts.* MH will adopt the interim standard upon transition to IFRS and will continue to recognize rate-regulated accounts for its financial reporting.

Overall, the transition to IFRS is not expected to have a significant impact on customer rates. Increases to operating and administrative expenses due to reductions in overhead eligible for capitalization will be substantially offset in the future by corresponding reductions in depreciation and amortization expense. The net impact of the transition to IFRS for 2015/16 is expected to be a decrease to net income of approximately $20 million. In addition to the net income impacts, retrospective application for changes in accounting resulting from differences from existing GAAP is required. For MH, the transition to IFRS will result in an initial adjustment to retained earnings of approximately $54 million and an adjustment to Accumulated Other Comprehensive Income (AOCI) of $445 million.

The following table identifies the consolidated transitional adjustments and projected 2015/16 net income impact of MH's transition to IFRS *(In millions of dollars):*

	IFRS IMPACTS INCREASE / (DECREASE)		
	Retained Earnings April 1, 2015	**AOCI**	**Net Income 2015/16**
Administrative Overhead	(56)		(57)*
Pension & Employee Benefits	(24)	(445)	3
Meter Compliance, Exchange and Sampling			5
Capital Taxes	-		3
Removal of Asset Retirement Costs from Depreciation	62		64
Change to Equal Life Group Method of Depreciation	(36)		(38)
Total	**(54)**	**(445)**	**(20)**

*net of reductions in amortization

The topics in the following table have been identified as having the highest potential impact to MH upon its transition to IFRS:

Topic	Issue
Rate-Regulated Accounting	- Prior to December 2013, IFRS did not include a standard that recognized rate-regulated accounting. In the absence of a such a standard, MH would be required to charge approximately $335 million in rate regulated accounts to retained earnings upon transition to IFRS and future expenditures on these items would be required to be expensed as incurred. - In its May 2012 meeting, the IASB supported giving priority to developing a standards-level project and detailed discussion paper for rate-regulated activities. This decision was based on the feedback the IASB received on its June 2011 Agenda Consultation. - As a result of the developments at the IASB, in September 2012 the AcSB extended the optional transitional deferral for rate-regulated entities by an additional one year to January 1, 2014. - In its December 2012 meeting, the IASB decided that an Exposure Draft for an Interim Standard should be developed as a temporary solution until the IASB completes its comprehensive project on rate-regulated activities. The interim standard would permit "grandfathering" of existing recognition and measurement policies for rate-regulated accounts and would require these accounts to be presented separately in the financial statements. - Supported by the actions of the IASB, in February 2013, the AcSB extended the optional transition date deferral to IFRS for rate-regulated entities by an additional one year to January 1, 2015. - In April 2013, The IASB issued the Exposure Draft "Regulatory Deferral Accounts" with comments to be received by September 4, 2013. The exposure Draft applied to first–time adopters of IFRS only, permitted grandfathering of existing rate-regulated accounting practices, and required regulatory accounts to be presented separately in the financial statements. - On January 30, 2014, the IASB issued an Interim IFRS (IFRS 14 *Regulatory Deferral Accounts*) for rate-regulated activities effective January 1, 2016 with earlier adoption permitted. Manitoba Hydro will early adopt the interim standard effective April 1, 2015 and will continue to recognize rate-regulated accounts upon its transition to IFRS.

Topic	Issue
Intangible Assets	- GAAP converged with IFRS effective for MH's 2009/10 financial statements. The impact of this change on prior years was a cumulative reduction to retained earnings of $37 million related to the write-off of ineligible research and promotional related expenditures.
Property, Plant & Equipment (PP&E)	- The IASB has approved an exemption for rate-regulated entities to carry forward existing PP&E balances as of the transition date to IFRS. - MH has established new components as part of their review for compliance with IFRS and has completed a depreciation study based on these new components. - MH will change from the Average Service Life method of calculating depreciation to the Equal Life Group approach so as to ensure that each asset within a pool is fully depreciated upon its retirement. - MH will remove the provision for asset removal costs (negative salvage) from depreciation rates as this is not an IFRS eligible cost for self-constructed assets. - The impacts in 2015/16 to net income from the change to the Equal Life Group method and the elimination of the provision for asset removal costs will result in an annual decrease in depreciation of $26 million.
Capitalization of Overhead Costs	- IFRS specifically states that administration and other general overhead costs are not eligible for capitalization. - Through to 2012/13, MH adjustments with respect to discontinuing the capitalization of overhead costs total $62 million. This amount grows to $65 million by 2014/15 including inflation. - MH will discontinue the capitalization of an additional $58 million annually of general overhead costs upon transition to IFRS in 2015/16. - The $58 million is comprised primarily of expenditures for training, services and administration and managerial related charges.

Topic	Issue
Pension Costs	- IFRS does not permit the deferral of experience gains and losses for calculating expected fund returns and does not permit the use of expected asset returns in determining the discount rate used to measure the pension obligation. - IAS 19 has been amended (effective January 1, 2013) such that all actuarial gains and losses are to be recognized in Other Comprehensive Income. - MH expects to reclassify unrecognized actuarial experience losses of approximately $445 million to Accumulated Other Comprehensive Income upon adoption of IFRS.
Employee Benefits	- IFRS requires the estimated obligation for the unvested portion of accumulating benefits to be recognized over the period of service. - IFRS also requires past service benefit charges to be expensed as incurred. - Upon transition, MH expects to recognize approximately $15 million in increases to obligations with corresponding adjustments to retained earnings for unvested sick leave and severance benefits. - In addition, MH expects to charge approximately $9 million to retained earnings for unamortized past service balances for Retirement Health Spending Plan amendments.

1.0 Introduction

In February 2008, The AcSB declared January 1, 2011 as the date for Canadian publicly accountable enterprises to commence using International Financial Reporting Standards (IFRS) as a replacement for Canadian Generally Accepted Accounting Principles (GAAP). The Public Sector Accounting Board (PSAB) standards requires that public-sector enterprises with self-sustaining commercial-type operations (government business enterprises) such as Manitoba Hydro (MH) follow IFRS. Since 2008, the ACSB has approved several optional one-year deferrals of the transition to IFRS for Canadian entities subject to rate-regulation.

Although IFRS and GAAP are both principles-based, there are a number of differences between IFRS and GAAP that will result in changes in the timing of when costs are recognized by MH. Prior to January 2014, the most significant difference for entities subject to rate-regulation is that IFRS did not include a standard that recognized rate-regulated activities.

In recognition of the importance of this issue to North American utilities, the IASB started deliberations on this topic back in 2008 and since that time has started a project on rate regulated activities, issued an exposure draft in 2009, discontinued the project in 2010, restarted the project in 2012, issued an exposure draft in 2013 and issued an interim standard permitting the recognition of rate-regulated accounts in January 2014 (effective January 1, 2016 with early adoption permitted). Given the many years of uncertainty as to whether or not rate-regulated accounting would be permitted by the IASB, the AcSB issued multiple optional one-year deferrals of the transition to IFRS for Canadian rate-regulated entities. The following table summarizes the optional one-year deferrals of transition to IFRS as issued by the AcSB:

AcSB Decision Date	Revised IFRS Transition Date	Effective Date for Manitoba Hydro
September 2010	January 1, 2012	April 1, 2012
March 2012	January 1, 2013	April 1, 2013
September 2012	January 1, 2014	April 1, 2014
February 2013	January 1, 2015	April 1, 2015

Manitoba Hydro adopted each of the optional one-year deferrals issued by the AcSB and will be transitioning to IFRS effective April 1, 2015 for its 2015/16 fiscal year with comparative information for the 2014/15 fiscal year. Upon transition, MH will early adopt the IFRS interim standard IFRS 14 *Regulatory Deferral Accounts* and will continue to recognize regulatory deferral accounts in its financial statements.

MH has completed its assessment of the major differences upon transition to IFRS and has identified adjustments to retained earnings and ongoing differences in the timing of the recognition of certain transactions. The impacts of the transition affect primarily the accounting for property, plant and equipment (PP&E), general and administrative overhead capitalized and pension and benefits.

The overall impacts from conversion to IFRS can be summarized in the following three categories:

a) Transitional Adjustments

MH's transition to IFRS will result in adjustments to opening Retained Earnings and Accumulated Other Comprehensive Income (AOCI) as IFRS generally requires retrospective application. Such adjustments are somewhat less onerous due to an exemption that allows rate-regulated entities to carry-forward the historical cost of its PP&E and the interim standard that permits first-time adopters of IFRS to maintain rate-regulated accounts upon transition to IFRS.

b) Ongoing differences

MH has identified ongoing differences in the timing of recognition of certain transactions under IFRS. Increases in the amounts reported as annual operating and administrative expense resulting from annual overhead related expenditures that no longer qualify for capitalization or deferral are substantially offset over time by reductions in annual depreciation and amortization charges.

The following table identifies the consolidated transitional adjustments and projected 2015/16 net income impact of the transition to IFRS and the related accounting changes:

	IFRS IMPACTS INCREASE / (DECREASE)		
	Retained Earnings April 1, 2015	**AOCI**	**Net Income 2015/16**
Administrative Overhead	(56)		(57)*
Pension & Employee Benefits	(24)	(445)	3
Meter Compliance, Exchange and Sampling			5
Capital Taxes			3
Removal of Asset Retirement Costs from Depreciation	62		64
Change to Equal Life Group Method of Depreciation	(36)		(38)
Total	**(54)**	**(445)**	**(20)**

*net of reductions in amortization

2.0 Overview of IFRS Conversion Project

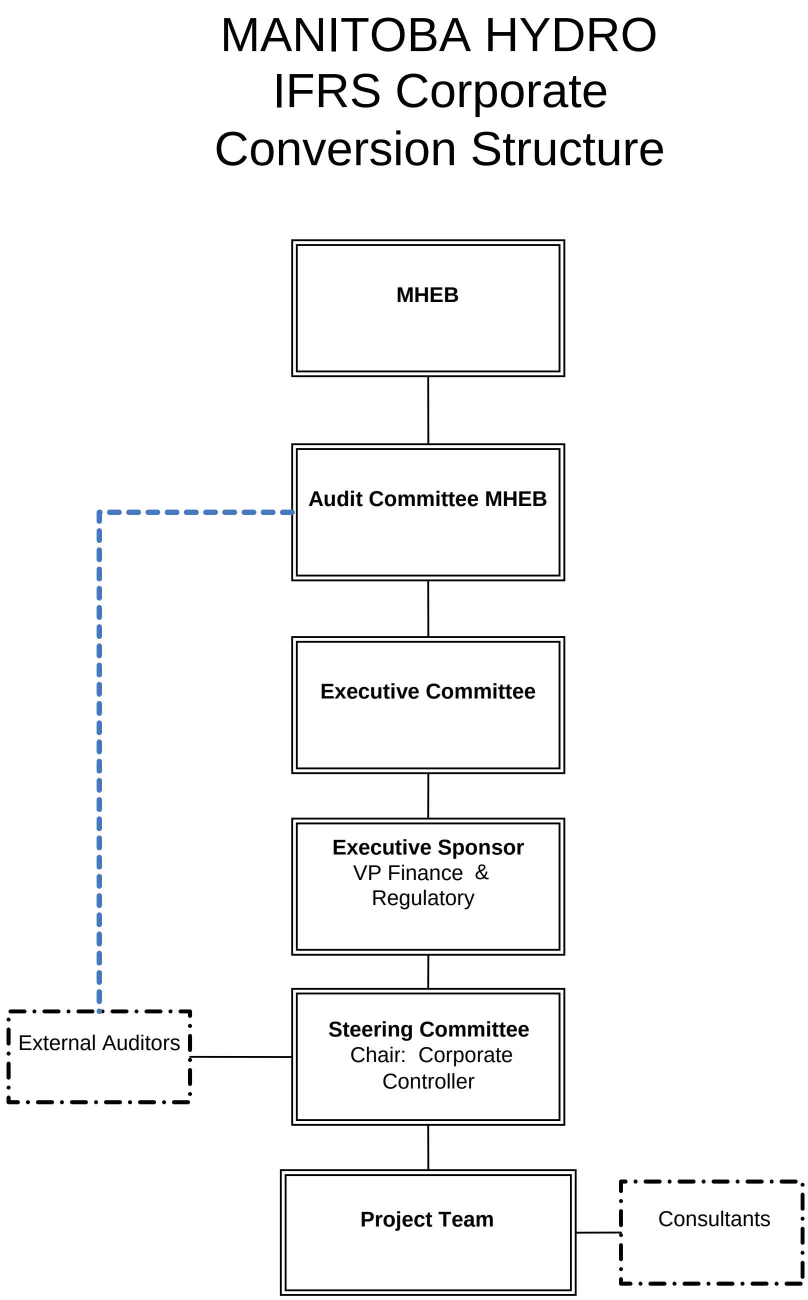
The following sections provide an overview of the MH IFRS conversion project structure, the project phases and the roles of the external consultants and auditors engaged to assist MH with the adoption of IFRS.

2.1 Project Structure

In 2008, MH formed a project team to manage the overall conversion to IFRS. Project team members work closely with a number of other employees throughout the Corporation to analyze the technical accounting issues and possible impacts of available options. The time commitment for these employees varies according to the complexity of the topics being considered.

In addition to the project team, a Steering Committee was established comprised of senior management representing each business unit, as well as other senior MH finance staff and a representative from MH's external auditor, Ernst & Young. The Executive Sponsor of the IFRS conversion project is the Vice-President Finance & Regulatory who has responsibility for the project and the communication of project results through the Executive Committee to the Audit Committee and the Manitoba Hydro-Electric Board (MHEB).

MH's formal project structure is summarized as follows:



2.2 Project Phases

The IFRS conversion project was divided into four phases with the following primary objectives:

1) Initial Assessment & Project Mobilization

- Establish project structure and mobilize project team;
- Develop initial project plan; and
- Identify potential gap differences between MH's policies and IFRS.

2) Detailed Design

- Prepare detailed gap analysis between MH's policies and IFRS;
- Assessment of the impact on key systems and related processes; and
- Update conversion plan.

3) Solution Development

- Develop comprehensive and detailed plans to convert systems and processes;
- Provide pro-forma financial statements and policies; and
- Develop detailed training programs.

4) Implementation

- Convert systems and processes;
- Prepare related documents and perform system testing; and
- Deliver IFRS training.

2.3 External Consultants

Through its project team and structure, MH managed the IFRS conversion project internally with the assistance of its primary consultant KPMG. Specifically, to date, KPMG has assisted the MH project team with:

- Project plan development, establishing priorities and monitoring progress;
- Detailed gap analysis of accounting and disclosure differences;
- Identifying accounting and system/process issues and raising awareness through educational sessions with management and staff;
- Application and interpretation of IFRS towards accounting policy and financial statement development;
- Assessment of information technology system requirements and possible solutions; and
- Detailed training and knowledge transfer.

There are also a number of technical areas involved in the IFRS project and MH has engaged Gannett Fleming Inc. and Ellement & Ellement to assist in the following areas:

Gannett Fleming Inc.:

- Application of IFRS as it applies to PP&E;
- Development of asset groupings that comply with IFRS componentization requirements;
- Development of IFRS compliant depreciation rates and related policies and practices applicable to each asset group;
- Development of historic cost and accumulated depreciation for the new asset groups; and
- Support for the regulatory review process.

Ellement & Ellement:

- Actuarial services on employee benefit obligations; and
- Review and consultation on pension calculations.

MH is in the process of hiring a consultant to assist with the technical system changes to facilitate financial reporting requirements under both IFRS and Canadian GAAP upon transition.

2.4 External Auditors

In order to opine on MH's consolidated financial statements for the year ended March 31, 2016 under IFRS, MH’s external auditors will be required to:

- Review MH's accounting policies under IFRS standards;
- Audit MH's opening balance sheet at April 1, 2014 under IFRS, perform audit procedures on individual IFRS adjustments and the restatement of comparative periods;
- Review information system, process and internal control changes; and
- Review and comment on financial statement presentation and disclosures under IFRS.

MH's current external auditor, Ernst & Young, has provided advice and has concurred with accounting changes that have been implemented to March 31, 2014. In addition, Ernst & Young has participated in discussions on various IFRS conversion issues particularly with respect to overhead costs eligible for capitalization and pension and benefits.

3.0 Key Areas of Interest

The following topic areas were analyzed as to their impact to MH upon conversion to IFRS:

1. Rate-Regulated Accounting
2. Goodwill & Intangible Assets
3. Property, Plant & Equipment
4. Capitalization of Overhead Costs
5. Employee Pension and Benefits
6. Financial Instruments
7. Leases
8. Customer Contributions
9. IFRS 1 - Initial Adoption of IFRS

The following sections provide an overview of each of these main topic areas.

3.1 Rate-Regulated Accounting

The following sections describe rate-regulated accounting under GAAP and IFRS and describe the IASB's process towards the establishment of a comprehensive project to study the impacts of rate-regulation on financial reporting and the establishment of an interim standard for rate-regulated accounting.

3.1.1 Rate-Regulated Accounting under GAAP

MH recognizes the impact of rate-regulation by applying various accounting policies that allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. This practice is commonly referred to as rate-regulated accounting. In the absence of rate-regulated accounting, these costs or credits may otherwise have been included in the determination of net income in the year incurred.

Effective January 1, 2009, GAAP was revised to remove a temporary exemption that permitted the recognition of assets and liabilities resulting from rate regulation. In the absence of specific guidance under GAAP, rate-regulated entities in Canada are permitted to reference and apply Accounting Standards Codification 980, "Regulatory Operations" (formerly FAS 71), issued by the US Financial Accounting Standards Board (FASB), which allows for the recognition of rate-regulated assets and liabilities under the following circumstances:

a) The enterprise's rates for regulated services or products are established by or subject to approval by an independent, third-party regulator;
b) The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services; and
c) It is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers.

Pursuant to a practice allowed by Canadian GAAP, MH has relied on this standard to maintain its current accounting treatment for rate-regulated assets and liabilities through to 2014/15.

3.1.2 Rate-regulated Accounting Under IFRS

Prior to January 30, 2014, IFRS did not include a standard that permitted the recognition of the economic effects of rate regulation. While IFRS did not preclude the recognition of regulatory assets and liabilities, it required that an asset or liability must meet the existing framework for recognition. The application of the IFRS framework in other countries did not typically result in the recognition of regulatory assets and liabilities.

The absence of specific IFRS guidance for rate-regulated accounting had been a significant concern of the Canadian utility industry since the AcSB decision to transition to IFRS. This issue was on the agenda of both the International Financial Reporting Interpretation Committee (IFRIC) and the IASB in 2008. The IASB added this project to its agenda in December 2008 because of concerns that differences of views would emerge in practice about whether it was appropriate for entities to recognize assets and liabilities arising from rate regulation and because of the ongoing requests for guidance on this issue.

The IASB issued an Exposure Draft (ED), *Rate-regulated Activities,* on July 23, 2009. The proposed standard allowed for assets and liabilities that arise from rate-regulated activities (within the scope of the ED) to be recognized under IFRS.

The responses to the ED were submitted in November 2009 and were mixed in terms of those supporting and opposing the proposed standard. MH provided commentary to the IASB on the

ED and also provided input into the Canadian Electrical Association (CEA), Canadian Gas Association and Canadian Energy Pipeline Association joint response.

The IASB met to discuss the comments received and to provide direction on the Rate-regulated Activities ED on February 17, 2010. At this meeting it was tentatively confirmed that entities subject to rate regulation should be allowed an additional exemption to IFRS to carry forward existing balances of PP&E and intangibles at transition to IFRS. No other decisions as to the future direction of the ED was reached however, as the diversity in responses to the ED made it difficult for the IASB to conclude on a future direction.

On May 6, 2010, the IASB approved an amendment to IFRS 1 (First-time Adoption of IFRS) to allow entities with rate-regulated activities to use the carrying amount of their PP&E and intangible asset balances from their previous GAAP as deemed cost upon transition to IFRS. These balances may include amounts that would not be permitted for capitalization under IAS 16 Property, Plant and Equipment, IAS 23 Borrowing Costs and IAS 38 Intangible Assets.

Due to the uncertainty of the timing of the resolution of this issue by the IASB, on September 8, 2010, the AcSB approved an optional one-year deferral for transition to IFRS for entities subject to rate regulation. The deferral was in recognition that entities with rate-regulated activities will require additional time to prepare themselves and the users of their financial statements for conversion to IFRS. As was the case with most other rate-regulated utilities in Canada, MH adopted this deferral.

On September 16, 2010, the IASB further reviewed the issue of rate-regulated accounting and concluded that members were clearly divided in terms of those supporting and those opposing the recognition of rate-regulated assets and liabilities. The IASB thus decided to discontinue the project on rate-regulated accounting on the basis that this topic would require more analysis and discussion than IASB resources would allow in consideration of other priorities.

3.1.3 IASB Agenda Consultation:

In July 2011, the IASB issued an Agenda Consultation document that requested feedback from its constituents as to its future strategic priorities and those areas of financial reporting that should be given the highest priority for improvement. The document listed the deferred projects of the IASB (including the rate-regulated accounting project) and requested suggestions for selecting new projects or removing projects to free up resources for other priorities. Comments on the IASB agenda consultation were due November 30, 2011. The CEA responded to the consultation indicating the need for the future agenda to address the impacts of rate regulation so as to reduce the extent of divergence in financial reporting emerging in the Canadian utility industry.

In March 2012, members the IASB met with the AcSB, the Big 4 accounting firms and industry representatives (including members from the CEA) to discuss the Canadian feedback from the IASB 2012 agenda consultation. One of the main issues discussed was the divergence in practice (IFRS, US GAAP and modified IFRS) emerging in the financial reporting of Canadian utilities due to a perceived lack of clarity regarding the accounting for rate-regulated activities under IFRS. It was suggested that an interim standard permitting the continued use of rate-regulated accounting in conjunction with the transition to IFRS be issued so as to reduce divergence in practice while a more comprehensive project was underway.

IASB representatives at the meeting acknowledged that this issue should be a priority and were amenable to an interim solution, but time and resources would prevent them from issuing an interim standard prior to 2015. Based on these discussions, on March 30, 2012, the AcSB announced a further extension of the optional deferral of the mandatory changeover date to IFRS for entities with qualifying rate regulated activities by an additional one-year to January 1, 2013.

In its May 2012 meeting, the IASB supported giving priority to developing a standards-level project for rate-regulated activities and in September 2012, the IASB decided to restart the project with the development of a comprehensive Discussion Paper to assess whether and how the IASB should develop an IFRS (or amend existing IFRSs) to reflect the impact of rate-regulation. In recognition that the development a comprehensive standards-level proposal will take several years, the IASB also discussed the potential for an interim IFRS for use until a comprehensive review is completed. As a result of the developments at the IASB, in September 2012 the AcSB extended the optional transitional deferral for rate-regulated entities by an additional one year to January 1, 2014.

In its December 2012 meeting, the IASB decided that an Exposure Draft for an Interim Standard should be developed as a temporary solution until the IASB completes its comprehensive project on rate-regulated activities. The interim standard would permit "grandfathering" of existing recognition and measurement policies for entities currently recognizing rate-regulated accounts and that these accounts would be required to be presented separately in the financial statements. Based on the actions of the IASB, in February 2013, the AcSB extended the optional transition date deferral to IFRS for rate-regulated entities by an additional one year to January 1, 2015.

In April 2013, The IASB issued the Exposure Draft *Regulatory Deferral Accounts* with comments to be received by September 4, 2013. The exposure Draft permitted grandfathering of existing rate-regulated accounting practices, required regulatory accounts to be presented separately in the financial statements and applied to rate-regulated entities that are first–time adopters of IFRS. MH provided comments to the IASB in support of the proposals in the exposure draft.

In its November 2013 meetings, the AcSB decided that with the issuance of an interim standard for regulatory deferral accounts by the IASB, they will not provide a further optional one year deferral of the mandatory date to transition to IFRS. As such, Canadian rate-regulated entities will be required to transition to IFRS effective January 1, 2015.

On January 30, 2014, the IASB approved the new interim standard IFRS 14, *Regulatory Deferral Accounts* which is effective January 1, 2016 with earlier adoption permitted. The key aspects of the new standard are as follows:

- An entity is permitted to apply the interim standard only if it:
    - is a first-time adopter of IFRS;
    - conducts rate-regulated activities; and
    - recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP.
- A rate-regulated entity is to continue to use its previous GAAP accounting policies, for the recognition, measurement and impairment of regulatory deferral account balances;

- The entity is to present regulatory deferral account balances as separate line items in the statement of financial position and to present movements in those account balances as a separate line item in the statement of profit or loss and other comprehensive income; and
- The entity is to provide specific disclosures to identify clearly the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances.

MH's operations fall within the scope of the new interim standard and it will early adopt the standard upon its transition to IFRS effective April 1, 2015.

3.1.4 Recent Developments

On September 17, 2014 The Discussion Paper "*Reporting the Financial Effects of Rate Regulation*" was issued and describes a type of rate regulation that contains elements of both cost recovery and incentive approaches. The Discussion Paper considers the common features of rate regulation and explores which of them, if any, creates a combination of rights and obligations that is distinguishable from rights and obligations arising from non rate-regulated activities. The Discussion Paper does not include specific accounting proposals, but rather explores several possible approaches that the IASB could consider when deciding how best to report the financial effects of a defined type of rate regulation. The deadline for comments for the Discussion Paper is January 15, 2015.

3.1.5 Rate Regulated Accounts – Summary

MH's rate-regulated assets consist of the following:

- **Power Smart Programs:** represent expenditures for the costs of the Corporation's energy conservation programs for both the electric and gas operations.
- **Site Restoration Costs:** represent expenditures on restoring MH electric (including diesel sites) and gas sites.
- **Deferred Taxes:** represent the unamortized balance of taxes paid upon the acquisition of Centra Gas by MH. Upon Centra's acquisition, Centra became a nontaxable entity which triggered this charge to MH.
- **Acquisition costs**: represent the internal and external costs associated with the acquisitions of Centra Gas and Winnipeg Hydro.

- **Regulatory costs**: represent past MH internal and external costs associated with electric and gas regulatory hearings.
- **Purchased gas variance account (PGVA)**: represents timing differences between the actual cost of gas to serve our market and the recovery of those costs through PUB approved sales rates. This account may, at any time, be in an asset or liability position.
- **DSM deferral liability**: represents the difference between actual and planned DSM spending.

MH's regulatory assets/liabilities meet the recognition criteria for regulatory deferral accounts under the interim IFRS 14 standard and as such, will continue to be recognized separately on the financial statements of MH upon transition to IFRS. The following tables summarize the actual balance sheet amounts for 2013-14 and projected income statement and balance sheet amounts for 2014-15 and 2015-16:

Table 3.1.1 Summary of Rate-Regulated Accounts

Comparative Year 2014-15

Item	Electric		Gas		Ending Balance Consolidated
	March 31 2014	Fiscal 2014-15*	March 31 2014	Fiscal 2014-15*	
Power Smart Programs	184	20	54	2	**260**
Site Remediation Costs	33	(2)	3	-	**34**
Deferred Taxes	-	-	27	(2)	**25**
Acquisition Costs	19	(1)	-	-	**18**
Regulatory Costs	-	1	1	1	**3**
PGVA	-	-	39	-	
Regulated Assets	**236**	**18**	**124**	**1**	**379**
DSM deferral	16	-	6	-	22
Regulated Liabilities	**16**	**16**	**6**	**6**	**22**

* 2014-15 projected expenditures net of amortization

Transition Year 2015-16

Item	Electric		Gas		Ending Balance Consolidated
	March 31 2015	Fiscal 2015-16*	March 31 2015	Fiscal 2015-16*	
Power Smart Programs	204	8	56	(4)	**264**
Site Remediation Costs	31	(1)	3	-	**33**
Deferred Taxes	-	-	25	(2)	**23**
Acquisition Costs	18	(1)	-	-	**17**
Regulatory Costs	1	1	2	(2)	**2**
PGVA	-	-	39	(29)	**10**
Regulated Assets	**254**	**7**	**125**	**(37)**	**349**
DSM deferral	16	(16)	6	(6)	-
Regulated Liabilities	**16**	**-**	**6**	**-**	**-**

* 2015-16 projected expenditures net of amortization

3.2 Goodwill & Intangible Assets

Effective for MH's 2009/10 fiscal year, GAAP was converged with IFRS for the recognition and measurement of Goodwill & Intangible Assets (GAAP section 3064). The new standard required retrospective application for the 2008/09 fiscal year.

3.2.1 Goodwill

MH acquired two major utility operations - Centra Gas in July 1999 and Winnipeg Hydro in September 2002. As a result of these acquisitions, MH has recorded Goodwill in the amount of $108 million which has remained unchanged since March 31, 2003. In accordance with GAAP, goodwill is not amortized; it is tested for impairment on an annual basis unless all of the following criteria have been met:

a) The assets and liabilities that make up the reporting unit have not changed significantly since the most recent fair value determination;
b) The most recent fair value determination resulted in an amount that exceeded the carrying amount of the reporting unit by a substantial margin; and
c) Based on an analysis of events that have occurred and circumstances that have changed since the most recent fair value determination, the likelihood that a current

fair value determination would be less than the current carrying amount of the reporting unit is remote.

The goodwill accounting requirements under GAAP and IFRS are converged, however, GAAP uses a different impairment testing model from IFRS. IFRS generally determines an impairment loss as the excess of the carrying amount above the recoverable amount of the cash generating unit to which the goodwill is allocated, rather than the difference between carrying amount and fair value of the reporting unit's goodwill as required for GAAP.

Under IFRS and GAAP, irrespective of whether there is any indication of impairment, an entity is required to annually test goodwill acquired in a business combination for impairment. The IFRS impairment testing model is applied at the cash generating unit level as compared to the GAAP model which is applied at the reporting unit level. In addition, IFRS allows for a reversal of an impairment loss for long lived assets, but it does not permit an impairment reversal for goodwill.

MH will incorporate these changes into an annual impairment test for the goodwill resulting from the acquisition of Centra Gas and Winnipeg Hydro. MH does not expect that the application of this impairment test upon transition to IFRS will result in any impairments.

3.2.2 Transitional Requirements (IFRS 1)

IFRS requirements are applied retrospectively when an entity adopts IFRS. Under IFRS 1, however, a first-time adopter has the optional exemption to not retroactively restate any business combinations that occurred prior to the date of transition to IFRS. MH will take the exemption and not restate any past business combinations.

3.2.3 Intangible Assets

The new Canadian standard (section 3064) includes criteria for an expenditure to qualify for recognition as an intangible asset and stipulates that research related expenditures are to be expensed in the period incurred. Under GAAP and IFRS, an expenditure is recognized as an intangible asset only if it meets one of the following "identifiable" criteria:

a) Is separable (i.e., is capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, asset or liability); or
b) Arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

Examples of identifiable intangibles are franchise rights, patents and licenses. In addition to the "identifiable" requirement, an entity must demonstrate its ability to control and obtain the future economic benefits from the intangible asset. For internally generated intangible assets, the new section 3064 also requires the following "research" related activities to be expensed as incurred:

a) Activities aimed at obtaining new knowledge;
b) The search for, evaluation and final selection of, applications of research findings or other knowledge;
c) The search for alternatives for materials, devices, products, processes, systems or services; and
d) The formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

Activities incurred after the selection of a chosen alternative for the project are eligible for capitalization with the exception of:

- Selling, administrative and other general overhead expenditures unless this expenditure can be directly attributed to preparing the asset for use;
- Identified inefficiencies and initial operating losses incurred before the asset achieves planned performance; and
- Expenditures on training staff to operate the asset.

The following sections summarize the impact of the convergence of GAAP with IFRS for MH with respect to intangible assets.

Power Smart Programs (Demand Side Management-DSM)

MH previously recognized electric DSM program expenditures as deferred costs and natural gas DSM program expenditures as rate-regulated assets. Upon the issuance of section 3064, an assessment determined that electric DSM activities did not meet the new intangible asset recognition criteria as these activities are not capable of being separated and transferred to another entity. As a result, MH reclassified unamortized electric related DSM charges to rate-regulated assets consistent with gas related DSM charges.

The new standard 3064 and IFRS specifically identify research, selling/promotion and indirect expenditures as ineligible costs for capitalization as an intangible asset. New DSM programs typically include research activities as well as promotional activities to introduce the DSM programs. Thus, upon adoption of section 3064, MH retrospectively adjusted unamortized DSM related balances for ineligible research and promotional related balances. The cumulative retained earnings adjustment associated with the April 1, 2008 DSM balance was approximately $5 million for electric related DSM charges and $1 million for gas related DSM charges.

Planning Studies

To comply with GAAP and IFRS, MH also reviewed its planning study expenditures and separated the expenditures into two categories:

a) Next generation and transmission studies; and
b) Emerging energy studies (i.e. wind studies to identify potential sites, hybrid electric vehicles).

The studies for next generation and transmission plant meet the criteria for recognition as an asset, but because such expenditures are intended to ultimately result in the construction of a tangible plant asset, deferral as an intangible asset is not appropriate. Therefore, these expenditures will be recognized as tangible construction in progress (CWIP) assets at the point in time when there is reasonable assurance that a commitment to construction will be made. Expenditures incurred prior to this point will be expensed in the period incurred.

Planning studies for emerging energies result in the accumulation of information and /or research data that enables MH to assess the impacts of energy options on its operations. Although emerging energy studies are necessary, the information generated from such studies does not normally result in the creation of separate or identifiable intangible assets and thus, does not meet the criteria for recognition as an asset. Therefore the costs associated with emerging energy activities will be expensed in the period incurred. The cumulative retained earnings adjustment associated with the April 1, 2008 planning studies balance for ineligible charges was approximately $25 million.

Information Technology - Application Development

MH reviewed its computer system application development process and concluded that, for the most part, expenditures of this nature met the requirements for recognition as intangible assets. However, research and planning related activities involving the need for a new system (software / hardware) or the research and feasibility analysis of alternative solutions should be expensed in the period incurred. The cumulative retained earnings adjustment associated with the April 1, 2008 Application Development Projects balance for ineligible charges was approximately $5 million.

3.2.4 Presentation and isclosure

GAAP and IFRS emphasize that intangible assets are separate and identifiable stand alone assets and as such, should be presented separately on the balance sheet rather than being classified in PP&E. Upon adoption of section 3064, MH reclassified (April 1, 2008 balances, net of accumulated amortization) $103 million of Computer Software development and $37 million of Easements from Property, Plant & Equipment to a separate category titled Goodwill and Intangible Assets.

3.2.5 Summary of Impacts

The following tables summarize the actual April 1, 2008 retained earnings adjustments with respect to the retrospective application of the new standard and the impact to net income for 2009/10 amounts:

Table 3.2.1 Summary of Transitional Adjustments to Intangible Assets - Charge to April 1, 2008 Retained Earnings
(In millions of dollars)

Item	Electric	Gas	Consolidated
Demand Side Management - Research and Promotion	5	1	6
Planning Studies	25	-	25
IT Application Development - Research	4	1	5
Other	1	-	1
Decrease to Retained Earnings	**35**	**2**	**37**

Table 3.2.2 Summary of Net Income Impacts from Intangible Assets - 2009/10
(In millions of dollars)

Item	Electric	Gas	Consolidated
Demand Side Management - Research and Promotion	(1)	(1)	(2)
Planning Studies	(2)	-	(2)
IT Application Development - Research	(1)	-	(1)
Other	-	-	-
Consolidated Amortization Offsets	**5**	**-**	**5**
Net Income Impact	**1**	**(1)**	**0**

The annual impacts to net income related to the changes in the standard for intangible assets reflects offsets for reductions in amortization and will vary in the future according to the degree of annual spending for these items.

3.3 Property, Plant & Equipment (PP&E)

Amounts recognized as PP&E under IFRS can differ from current GAAP both at the time of initial transition and subsequent to the transition to IFRS.

3.3.1 Transitional Requirements (IFRS 1)

In general, IFRS requires retrospective application. There are exemptions available from this general requirement under IFRS 1. An entity may elect to measure an item of PP&E at the date of transition to IFRS at its fair value and use that fair value as its deemed cost at that date. Alternatively, entities with rate-regulated activities may use the carrying amount of their PP&E and intangible asset balances from their previous GAAP as deemed cost upon transition; subject to an impairment test as at the transition date. As a result of the IFRS exemptions, no retroactive adjustment would be required to adjust any differences in capitalized costs.

MH supports that carrying forward historical cost is the appropriate treatment for a rate-regulated entity as existing and future rates are largely based on historical costs. MH will take the exemption that a rate-regulated entity can elect to use the historical carrying value of PP&E as its deemed cost on transition to IFRS.

3.3.2 Subsequent to the Transition to IFRS

Under existing GAAP, PP&E is recorded based on actual historical costs, which represents historical capitalized costs net of accumulated depreciation. Under IFRS, a company has the option of choosing either the historical cost model or the revaluation model for recording PP&E. Under the cost model, PP&E is carried at its net book value – i.e. historical cost less accumulated depreciation. Under the revaluation model, a class of PP&E can be carried at fair value less any subsequent accumulated depreciation. Determining the appropriate method of measuring fair value may require the use of professionally qualified valuators.

MH will continue with the cost model as the revaluation model would continuously change the value of PP&E, increasing the volatility of depreciation expense due to changes in the fair value of the assets and potentially increasing the need for customer rate changes.

3.3.3 Componentization/Depreciation

Under GAAP, depreciation must be recognized in a rational and systematic manner over the estimated useful life of the asset. Depreciation methods and estimates of the life and useful life are reviewed on a regular basis; however, GAAP does not specify the frequency of a "regular" basis. MH currently completes a depreciation study every five years and at that time adjusts its depreciation methods and estimates as appropriate.

Under GAAP, if an item of PP&E is made up of significant separable component parts, its cost must be allocated to the parts when practicable and when estimates can be made of the lives of the separate components. MH's policy is to group assets and amortize them such that the combined cost of the assets is amortized over the estimated average useful life of the group of assets.

IFRS requirements are similar to GAAP requirements. However, IFRS is more rigorous in terms of identifying separate components and addresses non-physical components of assets. IFRS permits the grouping of assets in determining the depreciation charge as long as the assets are from a homogeneous group, are individually insignificant in value and have similar useful lives. To the extent that assets include components with different lives that would materially impact annual depreciation expense, these components must be either separately depreciated or a methodology must be utilized that recognizes the differences in service lives for purposes of calculating depreciation expense. The recognition of non-physical components means that the costs of major overhauls or inspections associated with a capital asset may need to be recognized separately and amortized over a shorter life than the life of the physical asset. MH reviewed its existing components and determined that further componentization was required primarily for generation and distribution assets. In addition, MH determined that a change in the methodology for determining depreciation would also be required in order to avoid the need to componentize to a very detailed level.

With the assistance of its depreciation consultant, Gannett Fleming Inc., MH has established new component groupings consistent with the requirements of IFRS, assuming a change to the Equal Life Group procedure for group depreciation and has completed a depreciation study based upon these new component groupings. Normally, a depreciation study process is routine and involves updating the retirement experience of existing asset classes and reviewing operational factors to assess what new considerations are warranted. However, because of the new component groupings required under IFRS, an extensive effort involving accounting and operational personnel was required to research historical records and to assess operational factors of all new, existing and modified component groupings in order to establish account balances and to estimate service lives. MH has implemented the new service lives that resulted from the depreciation study during its 2011/12 fiscal year. The impact of this change in estimate is a decrease to depreciation expense of $36 million, $39 million and $42 million in 2011/12, 2012/13 and 2013/14, respectively.

MH completed a new depreciation study in 2014 with the assistance of the same depreciation consultant, Gannett Fleming, Inc., based on the asset components established in 2011/12. A detailed review of asset activity was conducted by MH's accounting and operating staff, to understand the actual impacts of the previous componentization changes, and to incorporate operational findings from recent asset condition assessment reviews. As a result, some of the cost allocation and service life estimates made during the initial componentization in 2011/12 were refined to reflect actual experience. The impact of these changes in estimate is a further decrease to depreciation expense of $26 million for 2014/15.

3.3.4 Change to Equal Life Group Method

A further IFRS related enhancement to depreciation calculations is that of moving from the Average Service Life (ASL) procedure to the Equal Life Group (ELG) procedure.

The ASL procedure, which has been used by MH in the past, calculates depreciation expense based upon the average life of all assets within each class. Under this method, those assets that have a shorter life than average will not be fully depreciated when retired from service. Conversely, other assets in this class that have a longer life than average will be over-depreciated when they are retired from service. Where an asset component grouping includes assets with different service lives, this method is viewed as problematic from an IFRS perspective because, except for those assets which have a life exactly equal to the average service life of that group, assets are being depreciated over a longer or shorter timeframe than their expected service life. Such would be the case with MH's existing asset component groupings.

The ELG procedure addresses these issues by developing depreciation rates with specific consideration of the expected retirement pattern for each asset type within each depreciation class. Every asset in the class is depreciated over its own expected service life and therefore is expected to be fully depreciated (not over or under depreciated) when it is removed from service. The resulting ELG depreciation expense calculations are in compliance with IFRS.

3.3.5 Gains and Losses on Disposal of Assets

Under existing GAAP, Canadian utilities are generally allowed to defer gains or losses that occur on the disposal of assets either through accumulated depreciation or a deferral account. Therefore the gains or losses are not immediately recognized in the income statement. MH currently recognizes gains and losses on the retirement of plant assets in accumulated depreciation.

IFRS requires that any gains and losses on disposal/retirement of assets be recognized immediately in income. As indicated in the previous section, when assets are retired from service under the ASL depreciation methodology, they are typically over or under depreciated. Under IFRS, assets that are over or under depreciated when they are removed from service will result in the recognition of a gain or loss. A further advantage of the ELG depreciation methodology is that depreciation expense is calculated such that the gains or losses upon asset retirements are minimized or eliminated which reduces the impacts on net income from asset retirements.

3.3.6 Elimination of Asset Removal Costs from Depreciation Rates

MH's depreciation rates currently include an amount for the costs to be incurred upon the removal of an asset. This is referred to as negative salvage value. This "precollection" of asset removal costs is maintained in accumulated depreciation reserves, and when assets are ultimately removed from service, the costs associated with the removal of an asset are charged against that reserve. Under this methodology, there are no direct charges against income for asset removal costs.

Negative salvage is not an eligible cost of self-constructed PP&E under IFRS. As the IASB allows rate-regulated entities to carry over the net book value of PP&E upon transition to IFRS, any existing negative salvage amounts included in accumulated depreciation will form part of the deemed costs of assets on transition.

Upon transition to IFRS, MH is eliminating the inclusion of negative salvage in depreciation rates as a means to offset other financial impacts associated with the transition. To the extent that it is necessary to remove an asset in order to replace it, the costs of removal of replaced assets will be capitalized as a cost component of the replacement asset. All other asset removal costs will be charged against income as incurred.

3.3.7 Provisions - Asset Retirement Obligations (ARO)

The concept of provisions under IFRS encompasses a wider range of circumstances that may result in the recognition of more liabilities than GAAP. Under IFRS, the threshold for recognizing a liability or provision is whether the underlying event giving rise to the liability or provision is probable or “more likely than not”. This is lower than the “likely” threshold under GAAP and could lead to additional provisions being recognized under IFRS. In addition, under IFRS provisions must be recognized when they can be reliably estimated, and only in rare circumstances is it presumed that an estimate cannot be made.

Under GAAP, an asset retirement obligation is recorded if an entity has a legal obligation to incur an expenditure in the future associated with the retirement of an asset currently in use. IFRS requires a liability to be recorded for constructive obligations as well as for legal obligations. A constructive obligation is derived from an entity’s actions by way of an established pattern of past practice, published policies or a specific current statement whereby the entity has indicated to other parties that it will accept certain responsibilities such that the other parties expect the entity to discharge its responsibilities.

Under GAAP, MH has recognized AROs for the decommissioning of a thermal generating station and for the partial decommissioning of a hydraulic generating station spillway. MH has reviewed its circumstances and has concluded that no new provisions exist pertaining to constructive obligations relating to ARO’s. MH will recognize such obligations when a commitment is made to decommission an asset and significant removal and/or remediation costs are expected to be incurred.

3.3.8 Capitalization of Borrowing Costs

Under current GAAP, carrying costs such as interest that are directly attributable to the construction of an asset may be capitalized (Interest During Construction or IDC). IFRS requires that actual borrowing costs for a period be capitalized to an asset that takes a substantial period of time to get ready for use. A substantial period of time is not a defined term and requires judgment in its application. MH has reviewed the average time period for construction of its major capital projects and has concluded that there will not be a significant change in projects eligible for interest capitalization.

MH has also reviewed the specific items included in the calculation of the interest capitalization rate for general asset additions and has made the necessary adjustments required for compliance with IFRS. The interest capitalization rate will now consist of the weighted average debt rate for all debt outstanding for the period, including anticipated borrowings in the upcoming fiscal year. MH implemented this change for its 2010/11 fiscal year under Canadian GAAP.

IFRS requires the segregation of specific and generally financed capital projects where possible in order to determine the borrowing costs eligible for capitalization. Therefore, where debt is designated to finance a particular capital project, MH will capitalize interest to the asset based on the interest rate from that designated debt issue.

3.3.9 Transitional Requirements (IFRS 1)

As the IASB allows rate-regulated entities to carry over the net book value of PP&E upon transition to IFRS, any existing capitalized interest included in PP&E may form part of the deemed costs of PP&E on transition. Therefore, no April 1, 2014 retroactive adjustment is required to adjust for differences in capitalized borrowing costs. In addition, there are no April 1, 2014 retroactive adjustments that are required for componentization, the change to ELG and the removal of negative salvage from depreciation rates. However, the net impact of the move to ELG and the removal of asset retirement costs from depreciation rates will result in an increase in retained earnings of $26 million in 2014/15.

3.3.10 Summary of Impacts

The following table summarizes the adjustments to retained earnings upon transition to IFRS for items pertaining to PP&E:

Table 3.3.1 Summary of Transitional Adjustments
(In millions of dollars)

Item	Electric Fiscal 2014/15	Gas Fiscal 2014/15	Consolidated
Change to ELG	(33)	(3)	(36)
Removal of the pre-collection of Retirement Costs	57	5	62
Increase to Retained Earnings	**24**	**2**	**26**

The following table summarizes the net income impact in 2015/16 for items pertaining to PP&E:

Table 3.3.2 Summary of Net Income Impacts
(In millions of dollars)

Item	Electric Fiscal 2015/16	Gas Fiscal 2015/16	Consolidated
Change to ELG methodology	(36)	(2)	(38)
Removal of Net Salvage	60	4	64
Net Income Increase (Decrease)	**24**	**2**	**26**

3.4 Capitalization of Overhead Costs

Under GAAP, MH has historically applied a full cost accounting methodology. Tangible and intangible assets are stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Overhead costs allocated to capital included support staff (Finance, Human Resources, Information Technology, Corporate, Legal, etc.), management time, training, depreciation, interest and facility related charges. This approach recognized that MH is both a construction and operating company and thus, maintains integrated resources in order to sustain all aspects of its operations.

IFRS requires that PP&E and intangible items that qualify for recognition as an asset shall be measured at cost which includes direct costs, such as materials, and all overhead costs that can be directly attributable to capital projects and intangible assets. IFRS identifies costs that are not eligible for capitalization such as the following:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including costs of advertising and promotional activities);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
d) Administration and other general overhead costs

Based on a review of its existing cost capitalization practices, and considering industry trends to move away from full cost accounting, MH has eliminated the following cost components from its capitalized overhead under GAAP (totaling $62 million annually through to the end of 2012/13):

Table 3.4.1 Costs no Longer Capitalized

Reduction to Costs Capitalized in fiscal 2008/09 (In millions of dollars)**:**

Interest and Facilities Overhead on Stores	**5**

Reduction to Costs Capitalized in fiscal 2009/10 (In millions of dollars)**:**

Executive Costs	2
Property Taxes on Facilities	2
Total	**4**

Reduction to Costs Capitalized in fiscal 2010/11(In millions of dollars)**:**

Interest on Common Assets (Facilities & Equipment)	12
General and Administrative Departmental Costs	5
Interest on motor vehicles	4
Total	**21**

Reduction to Costs Capitalized in fiscal 2012/13 (In millions of dollars)**:**

IT Infrastructure and Related Support	21
Building Depreciation and Operating Costs	11
Total	**32**

MH has completed its review of its capitalization methodology, including the cost components and activities currently being capitalized to assess costs eligible for capitalization under IFRS. This review considered all guidance available in the accounting standards, interpretations from the major international accounting firms (including Ernst & Young), as well as information from the CEA and other Canadian utilities. The review concluded that an additional $58 million (Electric - $55 M, Gas $3 M) of annual charges do not meet the IFRS criteria for capitalization. A summary of these ineligible charges is as follows:

Table 3.4.2 Additional Costs Ineligible for Capitalization upon Transition to IFRS
(In millions of dollars)**:**

Technical and Soft Skills Training	17
Service Areas (Management accounting, Treasury, HR, Safety, etc)	13
Administrative & Clerical Support Staff	13
Division and Department Manager	14
Fleet & Stores Administration	1
Total	**58**

The $58 million of ineligible charges consists of expenditures where a direct link to a specific capital asset cannot be made due to the nature of the expenditure or expenditures for items such as training which is explicitly disallowed for capitalization by IFRS unless incurred in respect of specific staff to commission a specific asset.

Systems and process changes to facilitate the accounting of capitalized costs in an IFRS compliant manner will be completed for implementation in fiscal 2014/15 to allow for comparative year reporting.

3.4.1Transitional Requirements (IFRS 1)

The IASB allows rate-regulated entities to carry over the net book value of PP&E upon transition to IFRS and thus, any existing capitalized costs included in PP&E may form part of the deemed costs of PP&E on transition. Therefore, no retroactive adjustment is required to adjust the differences in capitalized overhead costs to April 1, 2014. However, $56 million of expenditures capitalized under GAAP for the fiscal 2014/15 fiscal year will have to be adjusted to retained earnings upon transition to IFRS.

3.5 Employee Pension and Benefits

There are a number of differences that will result from adopting IFRS for defined benefit pension plans and other employee benefits.

3.5.1 Return on Plan Assets

The expected return on plan assets forms part of the annual pension expense. GAAP currently allows the expected return on plan assets to be based on either the fair value or a market-related value (moving average not exceeding a period of five years) of the assets. MH currently uses market-related values to estimate the expected return on plan assets and to apply experience gains and losses in the corridor calculation. A market-related value approach reduces volatility of actuarial gains and losses on the expected annual return on plan assets and subsequent amortization of balances outside the corridor, therefore, reducing volatility on annual pension expense.

Under IFRS, the expected return on plan assets is replaced by interest income calculated using the fair value of plan assets with the same discount rate used to measure the pension obligations.

3.5.2 Past Service Costs

GAAP allows past service costs associated with plan improvements/amendments to be recognized over the average remaining service life of the employee group. MH has implemented pension plan improvements that contain both vested and non-vested components and is currently amortizing those improvements over the average remaining service life of the employee group.

Under IFRS, past service costs associated with plan improvements/amendments are recognized as expense through profit or loss when the amendment or curtailment occurs.

3.5.3 Discount Rate

GAAP CICA section 3461.063 states that "*the discount rate used to determine the accrued benefit obligation shall be the interest rate determined by*

a) market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or
b) The interest rate inherent in the amount at which the accrued benefit obligation could be settled.

The Canadian GAAP requirement is similar to the IFRS standards. IAS 19.83 states that, "*the rate used to discount post-employment benefit obligations (both funded and unfunded) shall be determined by reference to market yields at the end of the reporting period on high quality corporate bonds. In countries where there is no deep market in such bonds, the market yields (at the end of the reporting period) on government bonds shall be used.*"

MH determines an annual discount rate which complies with the recommendations of the Canadian Institute of Actuaries, GAAP and IFRS. MH validates the selection of its discount rate with its external actuary, as well through the review of discount rates used by other Canadian utilities and the Civil Service Superannuation Board. Based on the similarities between the Canadian GAAP and IFRS requirements, MH does not anticipate changing the manner in which it determines its annual discount rate upon transition to IFRS.

3.5.4 Amended IFRS for Employee Benefits (IAS 19)

In April 2010, the IASB issued the "Defined Benefit Plans" Exposure Draft as part of its project to improve the accounting for employee benefits. This Exposure Draft did not require significant changes to the measurement provisions, but proposed significant changes to the recognition, presentation and disclosure of defined benefit plans. In June, 2011, the IASB published the amended standard on employee benefits; effective for annual periods beginning on or after January 1, 2013.

In addition to the fore-mentioned differences between IFRS and GAAP for pension accounting, the significant changes introduced by the amended standard that impact MH are as follows:

- That entities recognize re-measurements (actuarial gains and losses) and adjustments related to changes in the value of the defined benefit obligation and in the value of the plan assets only in Other Comprehensive Income (OCI) in the period in which they occur with no subsequent recycling to net income.
- Under IFRS, the expected return on plan assets is replaced by interest income calculated using the fair value of plan assets with the same discount rate used to measure the pension obligations. Currently under GAAP, the expected return on plan assets is calculated using a forecast rate of expected return appropriate for the plan asset mix of investments.
- That additional disclosure be provided that focuses on the characteristics of defined benefit plans and the risks associated with the plans.
- That the IFRS 1 exemption allowing an entity to adjust all unamortized actuarial gains and losses to retained earnings upon transition be eliminated.

3.5.5 Transitional Requirements (IFRS 1 – Amended IAS 19)

The amended IAS 19 is effective for MH for the 2014/15 IFRS comparative fiscal period, but early adoption is permitted. A first time adopter must retrospectively apply the Standard in the financial statements beginning on or after January 1, 2013. MH is adopting the amended IAS 19 upon transition to IFRS on April 1, 2015. The cumulative re-measured and restated unamortized experience gains and losses for the comparative year will be recalculated under IAS 19 and reclassified to Accumulated Other Comprehensive Income as of April 1, 2014.

3.5.6 Employee Benefits

MH offers accumulating benefits for service and currently under GAAP recognizes obligations for the vested portions only.

IFRS recognizes an obligation as an employee renders service regardless of vesting criteria. Therefore, under IFRS, actuarial obligations must be recognized for all accumulating benefit plans such as sick leave and severance.

Under IFRS, experience gains and losses resulting from actuarial valuations for certain long-term employee benefits such as MH's Retiree Health Spending Account and long-term disability must be expensed when determined. Under GAAP, these gains and losses may be amortized over the period until the next actuarial valuation (3 years for MH). Upon transition to IFRS, MH will adjust to retained earnings any unamortized gains and losses for such benefits.

The following table identifies the April 1, 2015 consolidated transitional adjustments associated with employee benefits:

Table 3.5.1 Transitional Adjustments – Employee Benefits
(In millions of dollars)

Item	Retained Earnings
Unamortized Past Service Amendments for Retiree Health Spending Account	(9)
Unamortized Experience Losses for Long-term Disability Account	-
Recognize Unvested Sick Leave liability	(7)
Recognize Unvested Severance liability	(8)
Increase (Decrease)	**(24)**

3.6 Financial Instruments

For the most part, GAAP is substantially harmonized with IFRS with the introduction of standards 3855 *Financial Instruments – Recognition and Measurement* and 3865 *Hedges*, implemented by MH in the 2007/08 fiscal year. Under the existing IFRS guidance, *Financial Instruments Recognition and Measurement*, MH's financial assets such as customer loans and accounts receivable would continue to be classified as loans and receivables, initially recorded at fair value and subsequently measured at amortized cost. Long term debt and other financial liabilities would continue to be initially recorded at fair value, and subsequently measured at amortized cost using the effective interest method.

Any unrealized foreign exchange gains and losses would be recorded to net income when there is no accounting hedge in place. U.S. sinking funds would continue to be classified as available-for-sale, however IFRS allows for a “natural” hedging of foreign exchange risk on foreign currency. Under IFRS, foreign exchange gains and losses related to available-for-sale monetary financial assets are recorded in net income. This means MH will continue to record foreign exchange gains/losses on its sinking fund investments in net income without the GAAP requirement to maintain a designated accounting hedge relationship between the U.S. sinking fund and the associated U.S. debt. Under both GAAP and IFRS, fair value changes related to changes in interest rates continue to be recorded in Other Comprehensive Income.

3.6.1 Hedges

As described above, GAAP requires that foreign exchange gains and losses on available for sale sinking fund assets be recorded in Other Comprehensive Income. However, designating these investments in a fair value hedge relationship has allowed MH to record offsetting foreign exchange translation gains and losses on the U.S. sinking funds (hedged item) and corresponding U.S. debt (hedging item) to net income. Under IFRS, the monthly translation of U.S. sinking fund investments would be recorded in net income as will off-setting changes in the fair value of the US debt, without the need for hedge accounting. Therefore, these fair value hedges are no longer required under IFRS.

MH’s current cash flow hedges between anticipated U.S. revenues (hedged item) and U.S. debt (hedging item) are not expected to be impacted by the transition to IFRS.

3.6.2 Commodity Contracts

Under IFRS, commodity contracts that can be settled either in cash or by another financial instrument, and do not meet the “own-use” scope exception are within the scope of IAS 39 and should be accounted for as a non-financial derivative, consequently subject to fair value accounting treatment. The “own-use” exception relates to contracts for non-financial items that were entered into and continue to be held for the purpose of the receipt or delivery of the non-financial item in accordance with the entity’s expected purchase, sale or usage requirements.

In principle, this exemption provides MH with the ability to exclude the majority of its commodity purchase and sales contracts from fair value accounting treatment, as the majority of its commodity contracts are used within the normal course of its business to deliver physical energy to and from varying locations. However, there are certain instances where the "own-use" exemption may not be available under IFRS. MH has developed an on-going review process of all commodity contract terms to assess whether the own use exemption applies.

Natural gas fixed price swaps utilized in the Primary Gas Fixed Rate Service have been identified as financial derivatives and are currently being measured at fair value on the balance sheet with changes in fair value recorded to net income. There are no accounting changes required for these contracts under IFRS.

3.6.3 IASB Future Developments – Financial Instruments

Since November 2008, the IASB has been working on a project to replace IAS 39, Financial Instruments: Recognition and Measurement with a new standard, IFRS 9. The IASB issued IFRS 9, Financial Instruments in July 2014. IFRS 9 is applicable from January 1, 2018 and focuses on the classification and measurement of financial assets and liabilities, impairment methodology for financial assets and hedge accounting.

The objective of this standard is to improve the usefulness of financial statements by simplifying the classification and measurement requirements for financial instruments. The impairment requirements will be applied to financial assets based on an expected credit losses model, rather than the current incurred loss model in IAS 39. New hedge accounting guidance will align hedge accounting with risk management, allowing certain changes to the hedge relationship after inception of the hedge.

Some of the potential impacts to MH from the new standard are as follows:

- Sinking funds would be reclassified from the current available-for-sale category to amortized cost;
- There will no longer be the requirement to recognize changes in fair value due to changes in interest rates for sinking fund assets in Other Comprehensive Income; and
- Hedge accounting effectiveness testing will be more closely aligned with risk

management and will be simplified by eliminating the 80% - 125% bright line and retrospective testing.

3.7 Leases

In general, the principles relating to accounting for leases under CICA standard 3065 Leases and IFRS are converged, except that:

a) IFRS uses the term “finance lease” in the same manner as Section 3065 uses “capital lease”;
b) IFRS does not subdivide finance leases into sales type leases and direct financing leases; and
c) The disclosure requirements differ.

Both standards classify leases based on whether or not substantially all the risks and rewards incidental to ownership are transferred. GAAP, however, provides more quantitative thresholds for evaluating whether a lease is a capital or operating lease. IFRS does not contain such quantitative thresholds. The interpretations provided under GAAP for determining whether an arrangement contains a lease are primarily the same under IFRS.

MH has reviewed its agreements and has not identified any additional leases that are required to be recognized upon transition to IFRS.

3.7.1 IASB Major Project on Leases

As part of a joint project with the US Financial Accounting Standards Board (FASB), in August 2010, the IASB issued an Exposure Draft on Leases. The Exposure Draft was proposed to correct for issues in existing standards which have been criticized for not meeting the needs of the users of the financial statements as they do not provide a faithful representation of leasing transactions. The IASB believes that existing standards fail to recognize rights and obligations that meet the definition of assets and liabilities within the existing IFRS framework. The significant changes proposed by the Exposure Draft were as follows:

- The distinction between finance and operating leases is discontinued;
- The Lessee would apply a *right-of-use* model that would recognize an asset for its right to use an asset and a liability for its obligation to make lease payments; and

- The Lessor would recognize an asset representing its rights to receive lease payments and, depending on the circumstances of the lease, recognize a lease liability while continuing to recognize the underlying asset or de-recognize the portion of the underlying asset that is transferred to the lessee.

In general, the feedback received on the ED indicated that the proposals were overly complicated and would be costly to implement. As a result, The IASB and FASB conducted a long and extensive outreach process across all major geographical regions involving round table discussions, preparer workshops, meetings, webcasts and publications. Overall, there has been support for the “right of use model” and it has generally been accepted that lease contracts result in assets and liabilities.

Having worked through many of the complications identified in the feedback, in May 2013, the IASB and FASB issued a revised exposure draft that incorporates many aspects of the earlier exposure draft and proposed a dual model approach for lessee accounting, under which a lessee would classify each lease as other Type A or Type B. As well, a lessee would recognize a right-of-use asset and a lease liability for all leases of more than 12 months and can choose not to do so for leases of 12 months or less.

The main feedback received was that the dual model proposed for lessees was too complex. As such, the IASB is recommending a single lease accounting model for lessees in which all leases would be recorded on the balance sheet except for short term leases and small ticket leases. The IASB also decided no significant changes are required to the current guidance offered to lessors in IAS 17, Leases.

Further deliberations are necessary before the IASB can issue the new standard, expected in 2015. FASB had decided to pursue its own standard.

3.8 Customer Contributions

Under GAAP, non-refundable contributions in aid of construction are separately recorded on the balance sheet and amortized to income on a straight-line basis as a reduction to depreciation over the life of the related item of PP&E. Refundable contributions are recorded in Other Long-term Liabilities by MH, and are refunded to customers if the criteria for the refund have been met.

Under IFRS, customer contributions are to be recognized as revenue; either immediately or over some future period of time. The customer contribution is recognized as revenue based upon fulfillment of the performance obligations of the underlying arrangement. An entity in receipt of a capital contribution is required to assess if separately identifiable services have been provided. That is, the utility must assess if the capital contribution is solely for the purpose of connecting the customer to the utility's grid such that the utility has no obligation beyond connecting the customer or if the contribution is also linked to the ongoing supply of energy. If it can be demonstrated that the service connection represents stand-alone value to the customer then the customer contribution should be recognized as revenue immediately. If it can be demonstrated that the contribution can be linked to the ongoing supply of energy, then all revenue arising from the contribution is deferred and amortized to income as the service is provided.

MH has reviewed its customer contribution arrangements and has concluded that the service connection to the customer does not have stand-alone value as the customers are not allowed to choose their energy distributor in Manitoba and are not able to resell connection assets that they do not own (such assets are the property of MH). The sole purpose of the connection is to provide access to an ongoing supply of energy (electricity or gas) from MH as a customer would derive no value from a connection without the future supply of energy. As the connection does not have stand alone value for the customer, the revenue should be recognized over time as energy is provided to the customer. If the arrangement does not specify a period, the revenue shall be recognized over a period no longer than the useful lives of the connection assets.

This will result in no impact to net income. However, classification on the income statement will change as the amortization of the contribution that was previously recognized as an offset in depreciation expense will now be recognized as revenue.

Under IFRS, the method for recognizing revenue related to refundable contributions would also change. The practice under Canadian GAAP excludes 100% of the refundable capital contributions from being amortized. Under IFRS, only the amount that is expected to be refunded would be excluded from the amount that is amortized into revenue.

3.9 IFRS 1 - Initial Adoption of IFRS

IFRS 1 requires an entity to comply with IFRS standards effective at the reporting date of the entity's first annual financial statements prepared and presented in accordance with IFRS. For MH, this would include IFRS standards in effect as of March 31, 2016. New accounting policies must be retrospectively applied (unless the relevant election is available and chosen) and adjustments made at the start of comparative period. Thus, for an entity adopting IFRS for the first time on April 1, 2015, it will be necessary to prepare and present a comparative opening balance sheet under IFRS as at April 1, 2014. In the comparative opening balance sheet, an entity must:

- Recognize all assets and liabilities that IFRS require be recognized;
- Derecognize from assets and liabilities those items for which IFRS do not permit recognition;
- Reclassify items when, in accordance with the GAAP previously followed by the entity, they would have been presented differently from how they would be in accordance with IFRS; and
- Apply IFRS in re-measuring all recognized assets and liabilities.

The underlying principle in IFRS 1 is that a first time adopter should prepare and present financial statements as if it had always applied IFRS. This will require the retrospective adjustment of accounts. However, there are certain exemptions and/or elections to this general principle which allow prospective application. In addition, IFRS 1 prohibits retrospective application in certain areas.

There are IFRS 1 elections for areas including financial assets and liabilities, hedge accounting, business combinations, value of PP&E, leases, financial instruments, decommissioning liabilities and borrowing costs. Where applicable, MH has addressed the transitional elections it is considering in the various sub-sections of this report.

4.0 Financial Reporting & Disclosure

There are a number of differences in the disclosure requirements of GAAP compared to IFRS. Set out below is a summary of the major differences that are likely to arise on an on-going basis.

4.1 On-Going Disclosures - Primary Statements

Under IFRS, there will be a number of changes to the primary financial statements which include the income statement, balance sheet and cash-flow statement. The following section outlines these changes.

Statement of Income

Under IFRS, the presentation of the income statement will be similar to GAAP. However, MH will be required to present its expenses based on their nature or by function. In addition, the new interim standard for Regulatory Deferral Accounts requires the net movement in all regulatory account balances that impact net income to be presented separately from the non-regulatory account income and expenses and other comprehensive income. This will be achieved by the use of a sub-total for the amount of profit or loss or other comprehensive income before the net movement in regulatory deferral account balances.

Statement of Financial Position (Balance Sheet)

MH expects changes to the current presentation of the statement of financial position with respect to balances currently disclosed as “other assets” and “other liabilities” which will need to be classified according to their type. In addition, MH will be required to follow the new interim standard for Regulatory Deferral Accounts and present sub-totals of all assets and liability balances before regulatory deferral account debit and credit balances which will be presented on separate lines.

Statement of Cash-Flow

Under IFRS, MH will have the choice of presenting its cash-flow on a direct or indirect basis. Currently MH discloses on a direct basis. In addition, MH will have the choice of presenting cash-flows from interest received as either operating or investing activities and cash-flows from interest paid as either operating or financing activities.

Incremental disclosures include:

- Separate disclosure of disposal proceeds and capital contributions received;
- Disclosure of total amount of interest paid (whether expensed or capitalized); and
- Reconciliation of cash-flows from operating activities to net income.

Other

MH will be required to present a separate statement of changes in equity. This will incorporate information currently presented in the statement of retained earnings and the statement of Accumulated Other Comprehensive Income.

4.2 On-Going Disclosures - Notes to the Financial Statements

Under IFRS, there will be a number of changes to the notes to the financial statements which are outlined below.

IFRS 14 - Regulatory Deferral Accounts

The new interim standard for Regulatory Deferral Accounts requires extensive disclosures intended to assist the reader in understanding the nature of, and the risks associated with the rate regulation that restricts the prices the entity can charge. As per the interim standard, for each portion of rate-regulated activities that is material to the financial performance of the entity, an entity shall disclose:

(a) a brief description of the nature and extent of the rate-regulated activities and the nature of the regulatory rate-setting process;

(b) the identity of the rate regulator; and

(c) how the future recovery of each regulatory deferral account debit balance or reversal of each regulatory deferral account credit balance is affected by risks and uncertainty, for example:

(i) demand risk;

(ii) regulatory risk; and

(iii) other risks (for example, currency or other market risks).

In addition to the above, the new standard requires an entity to disclose the following for each material regulatory account:

- The basis on which regulatory deferral account balances are recognized and measured initially and subsequently;
- A reconciliation of the carrying amount at the beginning and the end of the period;
- The amounts that have been recognized in the current period in the statement of financial position as regulatory deferral account balances to be recovered or reversed in the current or future periods;
- The amounts that are recognized in the statement of profit or loss and other comprehensive income relating to balances that have been recovered, amortized or reversed in the current period;
- The rate of return applicable to each class of regulatory deferral account; and
- The remaining periods over which the entity expects to recover or amortize the carrying amount of each regulatory deferral account.

Property, Plant and Equipment

Under IFRS, there will be the requirement to present a detailed continuity schedule for each class of PP&E. In addition, given that MH will elect to deem its net book value on transition as its opening cost under IFRS, this will require that accumulated depreciation be set to zero.

Pension Assets and Liabilities

IFRS requires disclosure of the amounts for the current and previous periods of: the present value of the defined benefit obligation; the fair value of plan assets, any surplus or deficit in the plan; and experience adjustments on plan liabilities and plan assets.

Provisions and Asset Retirement Obligations

IFRS requires disclosure of detailed continuity schedules for each class of provisions.

Harmonization of Accounting Policies

IFRS requires uniform accounting policies to be applied to all entities in a consolidated group. Manitoba Hydro will be harmonizing its accounting policy with respect to costs associated with its Meter Sampling, Exchange and Testing program. Prior to the transition to IFRS such costs were capitalized for the Electric operations and expensed for the Gas operations. The harmonization of accounting policies will result in an increase to net income of $5 million for 2015/16.

Other

IFRS requires disclosure of related party information, including details of the entity's parent and controlling party as well as greater disclosure of judgments and estimates in the financial statements.

4.3 Initial adoption of IFRS (IFRS 1)

The first accounts that are prepared under IFRS are required to include a number of extensive reconciliations and narratives showing the effects of the transition from GAAP to IFRS. This information must include details of key changes in accounting policies, IFRS 1 elections made and measurement differences from GAAP.

MH is in the process of reviewing changes in financial statement presentation, required disclosures and related system and process changes for transition to IFRS.

5.0 Key Systems & Processes

As identified early in the project, the conversion to IFRS will have impacts on systems and related business processes. MH established an information technology (IT) team to identify and address these impacts. As part of this work, MH reviewed the capability of its SAP system to produce the required financial information for the 2014/15 comparative fiscal period and forward. Through this review, MH concluded that, with modifications, the existing SAP system is capable of meeting the financial reporting requirements under IFRS. MH is also reviewing financial systems that interface with SAP to ensure they will also be capable of meeting the financial reporting requirements.

MH has issued an RFP seeking consulting expertise to assist with the design of the technical SAP system solution required to facilitate financial statement changes required as part of the transition to IFRS.

The key areas of IFRS that will impact systems and processes are:

5.1 Componentization of Property Plant & Equipment

This change will require that capital project forecasts and expenditures be further delineated into constituent components. The SAP system is capable of providing the framework necessary to facilitate these changes. Fixed Asset ledgers have been updated with new component groupings. There will be a large element of change management and training to ensure that new requirements are properly understood and adhered to across the organization.

5.2 Calculation of IFRS Compliant Depreciation

Under GAAP, depreciation expense calculations incorporate factors relating to the service life of assets and cost of removals using a mass property approach based upon historical plant values. Under IFRS, the depreciation method will change from the average service life method to the equal life group approach. The SAP asset management system is capable of providing the framework necessary for this work as new opening component balances are being determined and depreciation calculation processes utilizing the ELG approach have been put in place. There is a significant effort to transfer existing assets and ongoing projects into their new components. New routines will also be developed to ensure that asset retirements are identified and processed in more detail than previously required under GAAP.

5.3 Changes to Cost Allocations

Under IFRS, administration and other general overhead costs can no longer be capitalized. Work to ensure that the costing systems and processes capture and allocate costs to capital projects in a manner that is IFRS compliant is near completion. This required changes to activity rates used for capitalization, as well as changes to overhead rates and internal cost allocation routines. It required changes to time carding instructions and processes to ensure that costs charged are properly linked to the capital projects to which they pertain. The basic cost allocation framework developed in SAP was capable of meeting these requirements. Subsystems were assessed to ensure that the correct IFRS compliant information was being provided into the system and processed correctly.

Work to allow for the accounting of capitalized costs in an IFRS compliant manner will be completed for implementation in fiscal 2014/15 to allow for comparative year reporting.

5.4 Presentation of Regulatory Deferral Accounts

Under IFRS, regulatory deferral accounts will be required to be separated in the presentation of the Statement of Income and Statement of Financial Position. In addition, IFRS requires extensive note disclosure with respect to the regulatory deferral accounts. MH’s existing systems maintain separate accounts for each of its existing regulatory account balances and it is anticipated that these systems will be capable of capturing the information required for both the financial reporting and note disclosure requirements under IFRS.

6.0 IFRS Changes

MH is required to prepare its first set of IFRS financial statements in accordance with the standards that are in effect as at the end of the first year of adoption of IFRS (i.e. March 31, 2016). MH chooses its accounting policies based on these standards and then applies them from the beginning of the comparative period, i.e. from April 1, 2014. MH's preliminary accounting policy choices as set out in this report, should not therefore, be considered final and may continue to evolve as the IFRS standards themselves change both before and after the transition date.

The IASB has a very active agenda and a number of projects may impact MH significantly. The effective date of any IFRS amendments and new standards is usually 6-18 months after their publication date. However, the IASB considers all relevant facts including whether to allow early adoption. It is important to note that many IFRS requirements will not change between now and fiscal 2015/16. However, there are significant changes to IFRS that have been published which may have an impact to MH. There are several active projects of the IASB that may have implications to MH post transition to IFRS.

Set out below is a summary of recent IFRS changes that may be relevant to MH:

Table 6.1 Relevant IFRS Changes

Topic	Issues	Timing
Rate Regulated Accounting	In April 2013, the IASB issued an exposure draft "*Regulatory Deferral Accounts*" which proposed an interim standard permitting rate-regulated entities that are 1st time adopters of IFRS to continue to recognize their regulatory accounts on an interim basis until the comprehensive project on rate-regulated activities is complete.	On January 30, 2014, the IASB issued an interim standard IFRS 14 - *Regulatory Deferral Accounts* effective January 1, 2016 with earlier application permitted. MH will early adopt the new standard effective April 1, 2015 upon its transition to IFRS.
	The IASB committed to developing a Discussion Paper to assess whether and how the IASB should develop an IFRS reflecting the impact of rate-regulation.	On September 17, 2014 The Discussion Paper "Reporting the Financial Effects of Rate Regulation" was issued and describes a type of rate regulation that contains elements of both cost recovery and incentive approaches. The Discussion paper considers the common features of rate regulation and explores which of them, if any, creates a combination of rights and obligations that is distinguishable from rights and obligations arising from non rate-regulated activities. The deadline for comments for the Discussion Paper is January 15, 2015.

Topic	Issues	Timing
Financial Instruments	The IASB completed a three-part project to replace IAS 39, Financial Instruments: *Recognition and Measurement* with a new standard, IFRS 9. The three main parts of the project are: a) Classification and measurement; Eliminated Held-to-Maturity, Available-for-Sale, and Loans and Receivables categories. New categories for financial assets are limited to fair value and amortized cost. Classification of financial assets is based on cash flow characteristics and the business model in which the asset is held. b) Amortized cost and impairment (loan loss provisions); Introduced a new expected loss impairment model that will require more timely recognition of expected credit losses. c) Hedge accounting. The general hedging model attempts to: - Align hedge accounting more closely with risk management - Simplify effectiveness testing by eliminating the 80% - 125% bright line test. - More principal based approach to hedge accounting. - Address inconsistencies and weaknesses in the existing model in IAS 39.	Classification and measurement of financial assets and liabilities was completed in 2010 In November 2012, the IASB issued an exposure draft on limited amendments to classification and measurement requirements of IFRS 9. In July 2013 the IASB deferred the effective date of IFRS 9 from January 1, 2015 to an unspecified date, pending the completion of the impairment and classification and measurement phases. Supplementary document *Financial Instruments: Impairment* was published in January 2011. Comments closed in April 2011 and an exposure draft was issued March 2013. In September 2012, the IASB issued a review draft of the forthcoming general hedge accounting requirements to be added to IFRS 9. Comments received on this review draft were considered and in November 2013, a general hedge accounting model was finalized. A companion project to address macro hedging was started and a discussion paper is targeted for 2014. In July 2014, the IASB issued IFRS 9, Financial Instruments to replace IAS 39, effective January 1, 2018 with earlier application permitted. MH will not early adopt this standard.

Topic	Issues	Timing
Fair Value Measurement Guidance	New standard (IFRS 13 Fair Value Measurement) issued by IASB in May, 2011. - IFRS 13 defines fair value and sets out in a single standard a framework for measuring fair value. - Describes how to measure fair value when another IFRS standard requires fair value.	To be applied prospectively for annual periods beginning on or after January 1, 2013, with early application permitted.
Consolidations	New standard (IFRS 10 Consolidated Financial Statements) issued by IASB in May, 2011. IFRS 10 does not change consolidation procedures. It provides guidance on whether an entity should be consolidated by revising the definition of control. Establishes one control model that applies to all entities. June 2012, IASB published amendments to IFRS 10 to clarify the transitional requirements; limiting the requirement to provide comparative information to only the preceding comparative period.	IFRS 10 and the amendments to IAS 27 are effective for annual periods on or after January 1, 2013 and must be applied retrospectively. If adopted early, must be adopted with IFRS 11 (Joint Arrangements) and IFRS 12 (*Disclosure of Interests in Other Entities*).

Topic	Issues	Timing
Disclosure of Interests in Other Entities	IFRS 12 *Disclosure of Interests in Other Entities* was issued by the IASB in May 2011 and requires increased disclosure of relationships with subsidiaries. Expands disclosure requirements as parent now required to disclose summarized financial information for each subsidiary that has material non-controlling interest.	Effective for annual periods beginning on or after January 1, 2013, with earlier application permitted.
Presentation of Financial Statements	In June, 2011, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to change the grouping of items in OCI. Current and future changes to IFRS will result in increased recognition of items in OCI (eg. IFRS 9 Financial Instruments, IAS 19 Employee benefits). Items that could be reclassified to profit and loss at a future date (i.e. recycled) are to be classified separately from items that will never be recycled.	Amendments are effective for annual periods beginning on or after July 1, 2012.

Topic	Issues	Timing
Employee Benefits	In April 2010, the IASB issued the "Defined Benefit Plans" Exposure Draft as part of its project to improve the accounting for employee benefits. This Exposure Draft proposed significant changes to the recognition, presentation and disclosure of defined benefit plans. In June, 2011, the IASB published the amended standard on employee benefits; effective for annual periods beginning on or after January 1, 2013. The significant changes introduced by the amended standard that impact MH are as follows: • Entities recognize re-measurements (actuarial gains and losses) and adjustments in Other Comprehensive Income (OCI) in the period in which they occur with no subsequent recycling to net income. • The discount rate used to measure the defined benefit obligation will also be used to calculate the interest income on plan assets. • That additional disclosure be provided that focuses on the characteristics of defined benefit plans and the risks associated with the plans. • That the IFRS 1 exemption allowing an entity to adjust all unamortized actuarial gains and losses to retained earnings upon transition be eliminated. • The distinction between short-term and other long-term benefits is based on the expected timing of settlement rather than the employee's entitlement to the benefit.	On June 16, 2011 the IASB issued IAS 19 Employee Benefits, which is effective from January 1, 2013. These amendments finalize proposals in the exposure draft Defined Benefit Plans, published in April 2010. MH is adopting the amended IAS 19 upon transition to IFRS on April 1, 2015. Cumulative unamortized experience gains and losses as recalculated under IAS 19 will be reclassified to Accumulated Other Comprehensive Income at that time.

Set out below is a summary of IFRS projects that may be relevant to MH post transition to IFRS:

Table 6.2 Relevant IFRS projects

Topic	Issues	Timing
Leases	IASB and FASB are reconsidering the accounting for leases. An exposure draft was issued in August 2010 which included the elimination of operating and finance lease classifications. Comments indicated the proposed amendments were too complex. In May 2013, a revised exposure draft was issued proposing a dual approach to lease recognition (one approach for depreciable assets and one approach for land and long-lived property). The main feedback received on the 2013 exposure draft was that the dual model proposed was too complex. As such, the IASB is recommending a single lease accounting model for lessees and has decide no significant changes are needed to the current lessor accounting model.	The IASB expects to issue a new Leases Standard in 2015.

Topic	Issues	Timing
Revenue Recognition	IASB and FASB to develop a single comprehensive set of principles for revenue recognition on when and how revenue should be recognized; to improve comparability over a range of industries / companies and countries. Exposure Draft was issued in June 2010. Comments on original proposal found it too complicated. Re-Exposure Draft was issued in November 2011. The key principles on which the Standard is based – that revenue is recognized on transfer to the customer, measured at the transaction price – are consistent with much of current practice. The IASB and FASB believe the Standard will improve financial reporting by: • Providing a more robust framework for addressing issues as they arise; • increasing comparability across industries and capital markets; • providing enhanced disclosures; and • clarifying accounting for contract costs.	The IASB and FASB have completed their re-deliberations of the comments on the revised ED with respect to recognition and measurement principles, scope, disclosure and transition. Project staff have begun drafting the final Revenue Recognition Standard. The new standard IFRS 15 Revenue from Contracts with Customers was issued in May 2014 and is effective January 1, 2017 with early adoption permitted.

Topic	Issues	Timing
Amendment to IAS 16 Property, Plant and Equipment and IAS 38 Intangible Assets – Clarification of Acceptable methods of Depreciation and Amortization	The objective of the proposed amendments is to ensure that preparers do not use revenue-based methods to calculate charges for the depreciation or amortization of items of PP&E or intangible assets. This is because a revenue-based method reflects a pattern of economic benefits being generated from the asset, rather than the expected pattern of consumption of the future economic benefits embodied in the asset. On December 4, 2012, the IASB issued an Exposure Draft of proposed amendments to paragraph 62 of IAS 16 and paragraph 98 of IAS 38 to state that a method of depreciation/ amortization that is based on the revenue expected to be generated from the use of an asset in an entity's business is not an appropriate method. On May 12, 2014 the IASB published "*Clarification of Acceptable Methods of Depreciation and Amortization (Amendments to IAS 16 Property, Plant & Equipment and IAS 38 Intangible Assets)*" which amends the requirements of IAS 16 and IAS 38 to clarify that a depreciation method that is based on revenue that is generated by an activity that includes the use of an asset is inappropriate. This is because such methods reflect a pattern of *generation* of economic benefits that arise from the operation of the business of which an asset is part, rather than the pattern of *consumption* of an asset's expected future economic benefits.	The amendments to IAS 16 and IAS 38 are effective for annual periods beginning on or after January 1, 2016 with earlier application permitted.

7.0 Next Steps

The next steps in the project will focus on ensuring that key systems and processes meet the accounting and reporting requirements for the 2014/15 comparative year and forward. This work will be performed with the assistance of MH's internal IT staff and SAP consulting expertise.

7.1 Advancing Topics to Phase 4 - Implementation

Most topics are at the end of the solution development stage where recommendations are being drafted, and implementation plans are being implemented. Any substantial system and process changes that are deemed to be appropriate to optimize related internal accounting processes pertaining to overhead capitalization policies will be developed and implemented for fiscal 2014-15. Detailed discussions with MH's external auditor Ernst & Young to obtain confirmation that MH has interpreted and applied IFRS consistent with their interpretation are ongoing.

7.2 Changes to Key Systems and Processes:

For each accounting topic analyzed by MH, key systems and related processes and interfaces were identified. As outlined in section 5.0 of this document, the key system changes identified in the project pertain to impacts created by the additional componentization of PP&E assets and changes to overhead capitalization policies. The current focus is to implement planned changes, ensure all interfacing systems and processes are modified accordingly, document new systems and processes where required and train all users of the various systems and processes.

7.3 Training Programs

Throughout the project, MH has incorporated training into the various phases. Where possible, those most impacted by IFRS related changes have been involved in the development of solutions and identification of issues and related systems and processes. The next phase of the training process is to work with those groups to formalize detailed training programs so as to embed IFRS into the "business as usual" practices of MH. It is expected that this form of training will focus on the accounting policies that are changing, the reason for the change, and the impact on the systems and processes, as well as additional training for staff that are the most impacted on a day to day basis.

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

APPENDIX 5.5
OPERATING, MAINTENANCE & ADMINISTRATIVE EXPENSE

1.0 OVERVIEW OF OM&A EXPENDITURES

The purpose of this Appendix is to provide an analysis of Manitoba Hydro's Operating, Maintenance and Administrative (OM&A) costs on an actual and forecast basis.

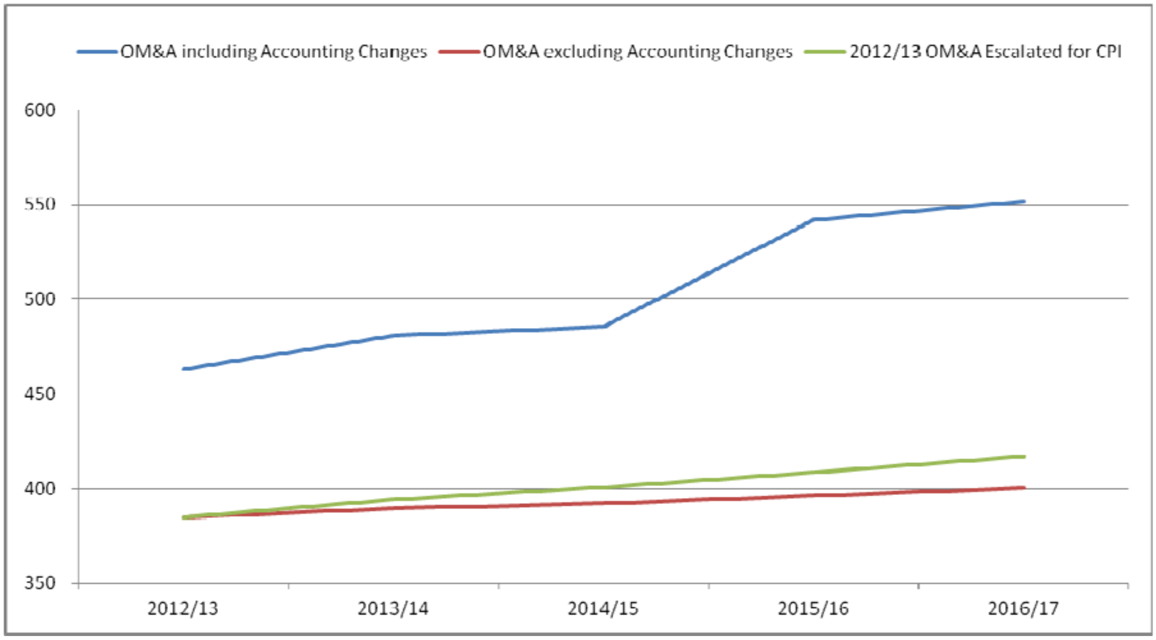
OM&A costs are recognized in accordance with Canadian Generally Accepted Accounting Principles (CGAAP) and apportioned to gas & electric utility operations through an integrated cost allocation methodology. In 2015/16 Manitoba Hydro will be transitioning to International Financial Reporting Standards (IFRS) and the impact on OM&A expenditures has been reflected in the forecasted costs for both the 2015/16 and 2016/17 fiscal years.

The following figures summarize OM&A costs and operating costs per customer for electric operations:

Figure 5.5.1 OM&A Costs Per Customer

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual Increase
Electric OM&A, including Accounting Changes	$ 462 952	$ 480 717	$ 485 755	$ 541 740	$ 551 675	
Less:						
Accounting Changes	(78 345)	(91 155)	(93 858)	(145 644)	(151 345)	
Electric OM&A, excluding Accounting Changes	$ 384 607	$ 389 562	$ 391 897	$ 396 096	$ 400 330	
% Increase (Decrease)		1.3%	0.6%	1.1%	1.1%	1.0%
Number of Customers	548 774	555 760	561 825	568 443	575 648	1.2%
Cost per Customer	701	701	698	697	695	
% Increase (Decrease)		0.0%	-0.5%	-0.1%	-0.2%	-0.2%
Manitoba CPI		2.4%	1.8%	1.9%	2.0%	2.0%

Figure 5.5.2 OM&A, Accounting Changes & CPI



As indicated above, Manitoba Hydro has maintained the average annual increase in OM&A costs at 1%, net of accounting changes, which is below inflation of 2.0% as a result of cost containment initiatives which focus primarily on reductions of staff positions. OM&A cost per customer is forecast to decline by an average of 0.2% per year over the 2012/13 to 2016/17 period.

IFF14 reflects the Corporation's commitment to a reduction of approximately 300 operational positions over the 3 year forecast period from 2014/15 to 2016/17 by leveraging attrition opportunities. These reductions will be achieved through the use of technology, consolidation and elimination of work processes where appropriate.

The following figure provides a summary of the committed position reductions by Business Unit.

Figure 5.5.3 Operational Position Reductions

	2014/15	2015/16	2016/17
President & CEO	2	2	2
General Counsel & Corporate Secretary	1	1	1
Human Resources & Corporate Services	33	27	21
Corporate Relations	3	2	1
Finance & Regulatory	4	3	3
Generation Operations	9	12	6
Major Capital Projects	1	1	-
Transmission	30	18	42
Customer Service & Distribution	46	19	13
Customer Care & Energy Conservation	16	6	5
Annual Commitment	**146**	**91**	**91**
Cumulative Commitment	**146**	**237**	**328**

Tab 5, Section 5.14 provides further discussion on some of the key initiatives being deployed by the Corporation in order to effectively manage its costs.

The 1.0% increase in OM&A has been achieved despite significant cost pressures primarily as a result of higher wages and salaries due to contract settlements greater than inflation and the impacts of merit and progression. A fair and competitive wage is necessary for attraction and retention purposes, to recognize the specialized education and training that several occupational groups are required to possess, and it also takes into account the challenging work conditions experienced by many employees in a customer service driven electric and natural gas utility environment (e.g. weather conditions, emergency response, confined spaces, etc).

The following figure outlines the contracted wage settlements in effect over the 5 year period.

Figure 5.5.4 Contracted Wage Settlements

Union	Effective Date	Contracted Wage Settlement
IBEW [1]	April 1, 2012	2.00%
All	January 1, 2013	0.00%
AMHSEE [2]	September 12, 2013	3.00%
All	January 1, 2014	2.75%
All	January 1, 2015	2.75%
Unifor/CEPU/ AMHSEE	January 1, 2016	2.50%

[1] 2% market adjustment for identified trade classifications in IBEW.

[2] 3% market adjustment for identified AMHSEE Trade Supervisors.

In addition to contracted wage settlements, employees are also entitled to receive either merit based on performance or salary progression through the pay schedules assigned to job classifications. Merit and progression combined with contracted wage settlements has resulted in an overall wage increase of 3 to 4% annually.

2.0 OM&A FORECAST PROCESS

Manitoba Hydro establishes an overall forecast for its OM&A expenses by taking into consideration the following factors:

- Costs of providing ongoing services;
- Special or non-recurring maintenance projects;
- Current and expected economic conditions;
- Changing business requirements; and
- Accounting changes and other significant items.

The overall forecast is apportioned to each of the business units and to the electric and gas operations based on current staffing levels, cost requirements that consider specific business, economic and other factors, and the implementation of cost containment initiatives. The Vice-President in charge of each business unit oversees the approved operating expenditures among the programs, division and utility operations for which they are responsible. Detailed departmental budgets support the approved business unit budgets.

The operating forecasts and detailed budgets form the basis for the OM&A forecast included in the Integrated Financial Forecast, which is presented to the MHEB for approval on an annual basis.

3.0 ACCOUNTING CHANGES IMPACTING OM&A EXPENDITURES

Although changes in accounting practices and policies have had a significant impact on the Corporation's OM&A expenditures, they are offset by reduced depreciation and amortization minimizing the overall impact to financial results and revenue requirement; see Appendix 5.6 for further information. Changes impacting OM&A are primarily a result of the planned implementation of IFRS in 2015/16 including related changes in prior years to support the transition.

Capitalization of Overhead Costs

Since 2009/10 Manitoba Hydro has removed approximately $62 million from its overhead capitalized under CGAAP in order to align the Corporation's capitalization policies with those of other Canadian utilities. Items removed from overhead capitalized include interest on equipment and facilities, building depreciation and operating costs, IT infrastructure and related support, as well as various corporate department costs. Manitoba Hydro has also reduced the capitalization of intangible asset costs.

With the implementation of IFRS in 2015/16, overhead capitalized will be reduced by a further $55 million reflecting the removal of training, service area costs, administrative & clerical support and divisional and department management costs which are no longer eligible for capitalization.

Pension & Benefits

In 2011/12, it was necessary for Manitoba Hydro to reduce its discount rate for the valuation of its pension and benefit obligations reflecting industry trends to calculate rates in accordance with recent guidance from the Canadian Institute of Actuaries and lower interest rates in general.

Further changes in 2015/16 under IFRS include the elimination of the amortization of past service costs and actuarial gains and losses as well and transitional adjustments related to pension and benefits.

The figure below provides a summary of the accounting and benefit changes impacting OM&A by fiscal year:

Figure 5.5.5 Summary of Accounting & Benefit Changes

SUMMARY OF ACCOUNTING & BENEFIT CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	IFF-14 2015/16 Forecast	2016/17 Forecast
Property Plant & Equipment					
CGAAP - Reduction to Costs Capitalized					
Stores Overhead	5,412	5,520	5,576	5,631	5,688
Executive Costs	2,122	2,165	2,187	2,208	2,230
Property Taxes on Facilities	2,122	2,165	2,187	2,208	2,230
Interest on Common Assets (Facilities & Equipment)	11,616	11,848	11,967	12,087	12,207
General & Administrative Departmental Costs	4,682	4,775	4,823	4,871	4,920
Interest on Motor Vehicles	3,933	4,011	4,051	4,092	4,133
IT Infrastructure & Related Support	20,022	20,422	20,626	20,833	21,041
Building Depreciation & Operating Costs	10,271	10,476	10,581	10,687	10,793
IFRS - Reduction to Costs Capitalized					
Technical & Softskills Training				15,980	16,140
Service Areas (Management Accounting, HR, Safety, etc)				12,270	12,393
Administrative & Clerical Support Staff				11,990	12,110
Division & Department Manager				13,320	13,453
Fleet & Stores Administration				1,140	1,151
PP&E Reduction to Costs Capitalized	60,180	61,384	61,997	117,317	118,491
Intangible Assets					
CGAAP - Reduction to Costs Capitalized	4,330	4,416	4,505	4,550	4,595
Pension & Benefits					
CGAAP -Changes (e.g. Discount Rate)	13,835	25,355	27,356	27,356	27,356
IFRS Changes				(2,700)	1,800
	13,835	25,355	27,356	24,656	29,156
Other					
IFRS - Meter Sampling, Exchange and Testing				(879)	(897)
Total OM&A Impact	$ 78,345	$ 91,155	$ 93,858	$ 145,644	$ 151,345

4.0 STAFFING REQUIREMENTS TO MANAGE OPERATIONS & CAPITAL INVESTMENT

Manitoba Hydro hires permanent, term, and temporary staff to manage, operate, maintain and construct the Corporation's assets and to provide service to customers. An Equivalent Full Time ("EFT") position represents a full time employee.

Manitoba Hydro has classified its EFTs into three categories in order to provide an analysis of the deployment of resources between operations and construction given Manitoba Hydro is entering a period of extensive capital investment and reinvestment.

1) Capital Construction EFTs – staff who charge their time to capital projects approved within the Capital Expenditure Forecast (CEF). The hours charged must be incremental, non-discretionary and directly attributable in order to be eligible for capitalization.

2) Operations and Maintenance EFTs – staff who charge time to operating and maintaining the electric, gas and various infrastructure assets of the corporation.

3) Governance, Support & Services EFTs:
   i. Governance – staff that provide direction and oversight regarding the actions, policies and decisions of the Corporation. This category includes functions such as internal audit, legal and executive.
   ii. Support Services - staff that provide corporate and divisional support services such as human resources, information systems, division and department managers, as well as departmental support activities not directly allocated to the capital construction or operations and maintenance functions of the corporation.

The following table and graph display EFTs for each category over the 5 year period:

Figure 5.5.6 Straight Time & Overtime EFTs

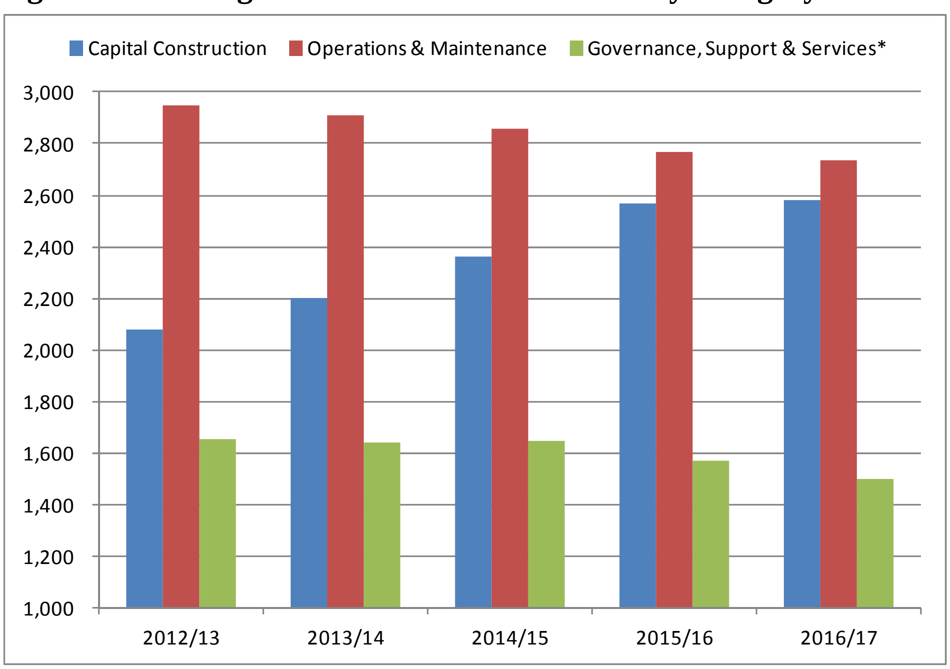
MANITOBA HYDRO
TOTAL EQUIVALENT FULL TIME (EFT) EMPLOYEES

(Straight Time & Overtime Combined)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)
Capital Construction	2 081	2 204	2 362	2 568	2 580	**5.6%**
Operations & Maintenance	2 946	2 908	2 855	2 765	2 733	**-1.9%**
Governance, Support & Services*	1 651	1 644	1 647	1 569	1 501	**-2.3%**
Total Corporation	**6 678**	**6 756**	**6 864**	**6 902**	**6 814**	**0.5%**

	Straight Time EFTs			Overtime EFTs		
	2012/13 Actual	2016/17 Forecast	Increase/ (Decrease)	2012/13 Actual	2016/17 Forecast	Increase/ (Decrease)
Capital Construction	1 942	2 357	415	139	223	84
Operations & Maintenance	2 768	2 575	(193)	178	158	(20)
Governance, Support & Services*	1 586	1 449	(137)	65	52	(13)
Total	**6 296**	**6 381**	**85**	**382**	**433**	**51**

*Note: A portion of Governance, Support & Services EFTs are capitalized through overhead

Figure 5.5.7 Straight-time and Over-time EFTs by Category



As depicted above, the average annual growth in EFTs for the 5 year period is 0.5%. During this period of significant capital investment, EFTs associated with capital construction are increasing. In contrast, consistent with Manitoba Hydro's commitment to manage its operating costs, the number of EFTs associated with operations & maintenance and governance & support activities are forecast to decline.

The decline in Operations and Maintenance EFTs and Governance, Support and Services EFTs is as a result of a comprehensive review of all positions to support cost containment efforts as well as a shift in some staff from operations to capital construction. The primary focus of the position review is to analyze work processes and functions and identify opportunities for elimination, consolidation or the use of technology that will result in staff reductions and efficiencies. Some of the specific initiatives in progress which result in reductions include:

- Consolidation of rural district offices;
- Implementation of efficiencies gained as a result of new technologies such as Mobile Workforce Management (MWM);
- Organizational realignments; and
- Review and alignment of trainee and summer student levels.

See Tab 5, Section 5.14 for further details on cost containment initiatives.

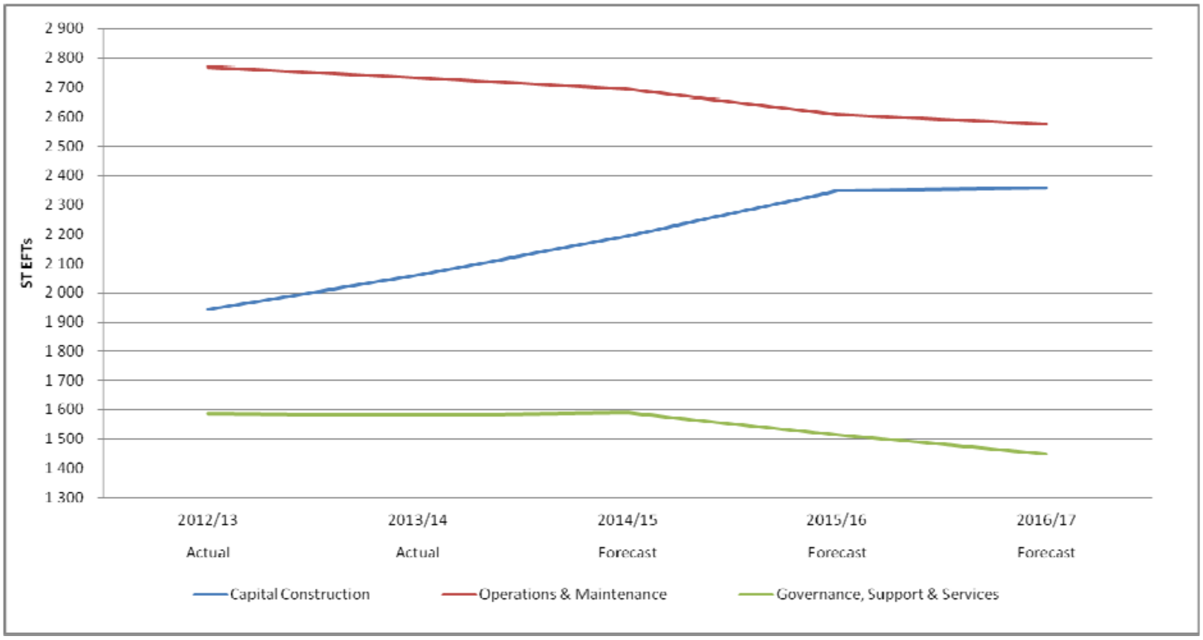
The figures below display straight time and overtime EFTs for each Business Unit, by category. Straight time and overtime EFT levels are influenced by different business requirements and explanations for significant changes over the 5 year period are provided below.

Figure 5.5.8 Straight Time EFTs by Business Unit

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES BY BUSINESS UNIT

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)	Notes
Capital Construction	2	1	0	0	0		
Operations & Maintenance	26	24	25	25	25		
Governance, Support & Services	21	18	17	16	15		
President & CEO	**49**	**43**	**42**	**41**	**40**	**-4.8%**	**1**
Capital Construction	5	9	6	6	6		
Operations & Maintenance	13	13	13	13	12		
Governance, Support & Services	22	22	26	25	24		
General Counsel & Corporate Secretary	**40**	**44**	**45**	**44**	**42**	**1.4%**	
Capital Construction	110	114	145	137	137		
Operations & Maintenance	74	75	73	76	75		
Governance, Support & Services	623	622	611	583	563		
Human Resources & Corporate Services	**807**	**811**	**829**	**796**	**775**	**-1.0%**	**2**
Capital Construction	39	38	42	42	43		
Operations & Maintenance	5	5	5	5	5		
Governance, Support & Services	42	41	43	41	40		
Corporate Relations	**86**	**84**	**90**	**88**	**88**	**0.6%**	
Capital Construction	2	8	3	2	2		
Operations & Maintenance	35	29	29	28	27		
Governance, Support & Services	112	114	120	115	113		
Finance & Regulatory	**149**	**151**	**152**	**145**	**142**	**-1.2%**	
Capital Construction	261	294	291	282	285		
Operations & Maintenance	628	673	669	665	661		
Governance, Support & Services	178	129	126	127	124		
Generation Operations	**1,067**	**1,096**	**1,086**	**1,074**	**1,070**	**0.1%**	
Capital Construction	185	201	230	295	296		
Operations & Maintenance	5	7	7	5	5		
Governance, Support & Services	11	11	19	20	19		
Major Capital Projects	**201**	**219**	**256**	**320**	**320**	**12.7%**	**3**
Capital Construction	567	589	645	689	689		
Operations & Maintenance	855	865	819	806	789		
Governance, Support & Services	319	308	307	284	264		
Transmission	**1,741**	**1,762**	**1,771**	**1,779**	**1,742**	**0.0%**	
Capital Construction	680	707	725	763	769		
Operations & Maintenance	791	695	705	667	659		
Governance, Support & Services	183	252	251	237	226		
Customer Service & Distribution	**1,654**	**1,654**	**1,681**	**1,667**	**1,654**	**0.0%**	
Capital Construction	91	97	106	131	130		
Operations & Maintenance	336	348	348	318	317		
Governance, Support & Services	75	65	69	65	61		
Customer Care & Energy Conservation	**502**	**510**	**523**	**514**	**508**	**0.3%**	
Capital Construction	1,942	2,058	2,193	2,347	2,357	5.0%	
Operations & Maintenance	2,768	2,734	2,693	2,608	2,575	-1.8%	
Governance, Support & Services*	1,586	1,582	1,589	1,513	1,449	-2.2%	
Total Corporation	**6,296**	**6,374**	**6,475**	**6,468**	**6,381**	**0.3%**	

Figure 5.5.9 Straight Time EFTs by Category



The following provides explanations for Business Units where straight time EFTs that have significantly increased or decreased as shown in Figure 5.4.8:

1) The decrease in EFTs in the President & CEO Business Unit is primarily due to reorganizations which resulted in the transfer of EFTs to Human Resources & Corporate Services, General Counsel & Corporate Secretary and Corporate Relations.

2) The decrease in EFTs in the Human Resources and Corporate Services Business Unit primarily relates to the elimination of various positions throughout the area primarily through outsourcing, implementing efficiencies gained from new technologies and realignment of duties.

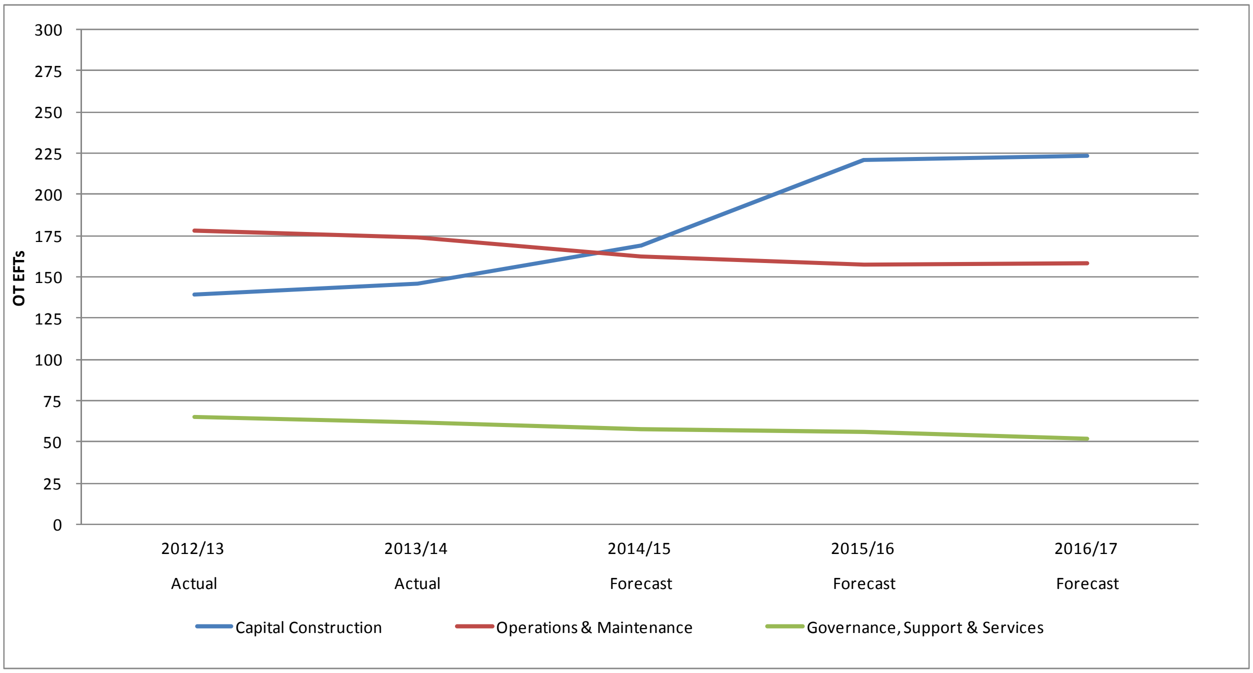
3) The increase in EFTs in the Major Capital Projects Business Unit primarily relates to additional resource requirements for major new generation and transmission projects such as the Keeyask Generating Station, Bipole III, and Pointe Du Bois Spillway Replacement, partly offset by the Wuskwatim Generating Station becoming operational in 2013/14.

Figure 5.5.10 Overtime EFTs by Business Unit

MANITOBA HYDRO
OVERTIME EQUIVALENT FULL TIME EMPLOYEES (EFT) BY BUSINESS UNIT

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)	Notes
Capital Construction	0	0	0	0	0		
Operations & Maintenance	0	0	0	0	0		
Governance, Support & Services	0	0	0	0	0		
President & CEO	**0**	**0**	**0**	**0**	**0**	**0.0%**	
Capital Construction	0	0	0	0	0		
Operations & Maintenance	0	0	0	0	0		
Governance, Support & Services	0	0	0	0	0		
General Counsel & Corporate Secretary	**0**	**0**	**0**	**0**	**0**	**0.0%**	
Capital Construction	2	3	4	4	5		
Operations & Maintenance	2	2	2	2	2		
Governance, Support & Services	11	12	11	12	11		
Human Resources & Corporate Services	**15**	**17**	**17**	**18**	**18**	**4.8%**	
Capital Construction	1	1	2	2	2		
Operations & Maintenance	0	0	0	0	0		
Governance, Support & Services	1	1	1	1	1		
Corporate Relations	**2**	**2**	**3**	**3**	**3**	**12.5%**	
Capital Construction	0	0	0	0	0		
Operations & Maintenance	0	0	0	0	0		
Governance, Support & Services	0	0	0	0	0		
Finance & Regulatory	**0**	**0**	**0**	**0**	**0**	**0.0%**	
Capital Construction	20	21	23	22	22		
Operations & Maintenance	59	65	59	58	58		
Governance, Support & Services	18	14	12	11	10		
Generation Operations	**97**	**100**	**94**	**91**	**90**	**-1.8%**	**1**
Capital Construction	23	36	46	97	97		
Operations & Maintenance	0	0	0	0	0		
Governance, Support & Services	1	1	2	2	2		
Major Capital Projects	**24**	**37**	**48**	**99**	**99**	**47.5%**	**2**
Capital Construction	46	49	55	55	55		
Operations & Maintenance	67	70	66	64	65		
Governance, Support & Services	24	23	22	20	19		
Transmission	**137**	**142**	**143**	**139**	**139**	**0.4%**	
Capital Construction	47	36	39	41	42		
Operations & Maintenance	49	36	34	32	32		
Governance, Support & Services	10	11	10	10	9		
Customer Service & Distribution	**106**	**83**	**83**	**83**	**83**	**-5.4%**	**3**
Capital Construction	0	0	0	0	0		
Operations & Maintenance	1	1	1	1	1		
Governance, Support & Services	0	0	0	0	0		
Customer Care & Energy Conservation	**1**	**1**	**1**	**1**	**1**	**0.0%**	
Capital Construction	139	146	169	221	223	13.1%	
Operations & Maintenance	178	174	162	157	158	-2.9%	
Governance, Support & Services*	65	62	58	56	52	-5.4%	
Total Corporation	**382**	**382**	**389**	**434**	**433**	**3.3%**	

Figure 5.5.11 Overtime EFTs by Category



The following provides explanations for Business Units where overtime EFTs have significantly increased or decreased as shown in Figure 5.4.10:

1) The decrease in EFTs in the Generation Operations Business Unit in the forecast years is primarily due to elevated maintenance requirements in 2013/14 at various generating stations as well as emergency work related to the fire at the Jenpeg Generating Station. In addition, further reductions are reflected in the forecast period as a result of cost containment strategies such as automation of the Pointe du Bois Spillway.

2) The increase in overtime EFTs in the Major Capital Projects Business Unit is related to requirements to protect key in-service dates primarily for the Keeyask Generating Station, Bipole III and the Pointe du Bois Spillway Replacement.

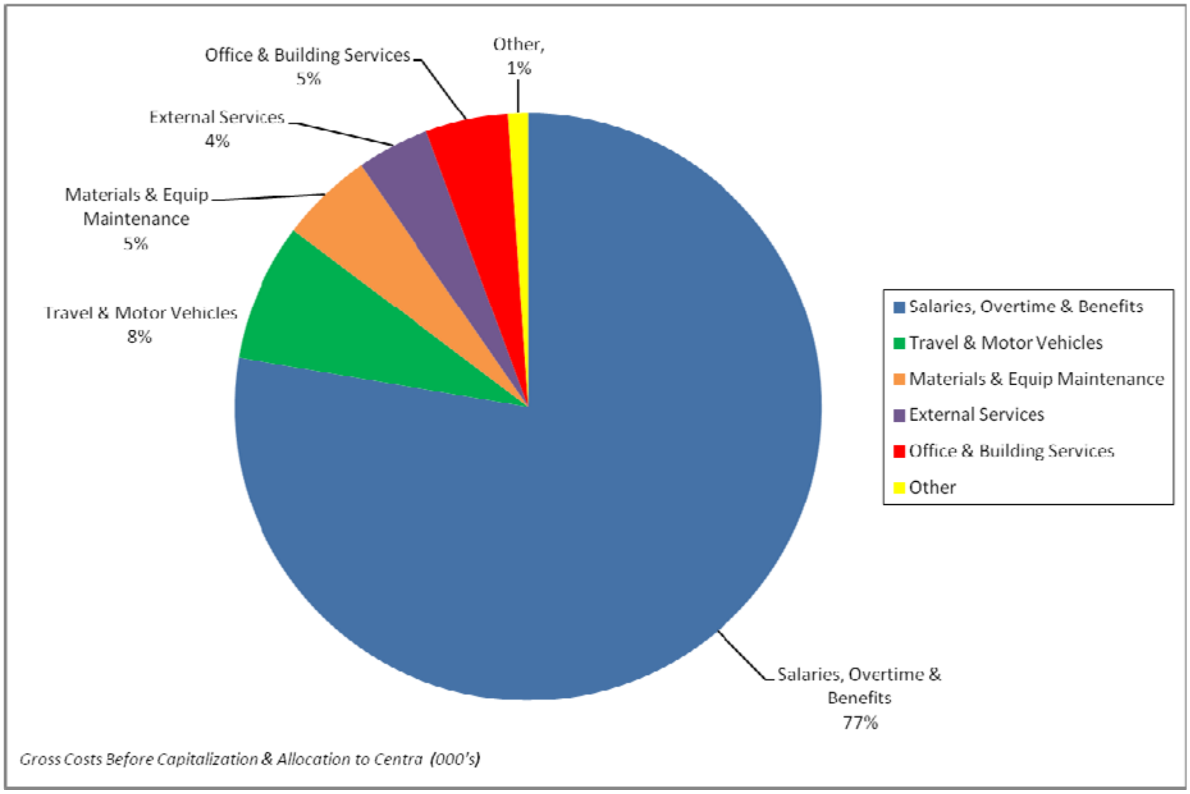
3) The decrease in overtime EFTs in the Customer Service & Distribution Business Unit is primarily related to unplanned storm restoration work and the completion of the Mobile Workforce Management capital project in 2012/13.

5.0 ANALYSIS OF COSTS BY CATEGORY INCLUDING OPERATING/CAPITAL ALLOCATION

Costs incurred by the Corporation are categorized as cost elements which describe the type of expenditure, such as wages & salaries, benefits, travel, materials, consulting, etc.

The following chart provides a graphical depiction of the major cost element components for 2013/14 actual expenditures excluding capitalization impacts and allocation of costs to Centra Gas.

Figure 5.5.12 OM&A by Category 2013/14



The following table provides a summary of Manitoba Hydro's actual and forecast costs by cost element over the 5 year period:

Figure 5.5.13 OM&A by Cost Element

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)	Note
Wages & Salaries	$ 466 165	$ 480 511	$ 502 692	524 552	533 997	3.5%	1
Overtime	61 031	62 365	61 709	71 080	73 121	4.8%	2
Employee Benefits	130 886	157 094	160 592	155 892	158 992	5.3%	3
Sub-Total	658 082	699 970	724 993	751 523	766 109		
Less: Labour & Benefits Charged to Capital	(215 491)	(234 510)	(256 588)	(282 335)	(287 969)	7.6%	4
Labour & Benefits Charged to Operations*	442 591	465 460	468 405	469 188	478 140	2.0%	5
Other Costs							
Employee Safety & Training	4 463	4 596	5 225	5 188	5 175	3.9%	6
Travel Expenses	31 194	31 915	31 766	31 628	31 634	0.4%	
Motor Vehicle	29 516	29 670	29 682	29 699	29 699	0.2%	
Materials & Tools	24 806	27 920	26 700	26 090	26 090	1.5%	
Consulting & Professional Fees	10 817	14 657	14 349	12 395	12 237	4.6%	7
Construction & Maintenance Services	16 259	16 775	19 364	18 580	18 580	3.6%	8
Building & Property Services	25 644	28 978	27 738	27 297	27 297	1.8%	
Equipment Maintenance & Rentals	14 680	15 007	16 120	16 191	16 191	2.5%	9
Consumer Services	5 050	5 277	5 323	5 323	5 323	1.3%	
Computer Services	849	678	985	1 020	1 019	7.2%	
Collection Costs	4 261	3 125	4 078	4 078	4 078	1.0%	
Customer & Public Relations	6 731	5 610	5 334	5 344	5 316	-5.5%	10
Sponsored Memberships	1 767	1 249	1 764	1 737	1 737	2.6%	
Office & Administration	13 874	14 724	15 722	15 721	15 717	3.2%	11
Communication Systems	1 817	1 963	1 928	1 928	1 928	1.6%	
Research & Development Costs	3 372	2 195	2 747	2 747	2 747	-2.4%	
Miscellaneous Expense	2 040	1 485	954	900	900	-17.2%	12
Contingency Planning	-	-	2 594	2 610	2 657		
Operating Expense Recovery	(13 997)	(17 808)	(13 468)	(13 649)	(13 647)	0.0%	13
Strategic Initiative Funding			870	3 640	6 317		14
Sub-Total	183 143	188 016	199 774	198 468	200 994		
Less: Other Costs Charged to Capital	(29 327)	(31 503)	(33 329)	(34 647)	(34 818)	4.4%	15
Other Costs Charged to Operations*	153 815	156 513	166 444	163 821	166 177	2.0%	5
Total	**596 406**	**621 973**	**634 849**	**633 009**	**644 317**	2.0%	
Less:							
Capitalized Overhead	(69 720)	(74 446)	(81 265)	(24 578)	(24 824)	-13.2%	16
Operating and Administration Charged to Centra	(63 735)	(66 810)	(67 829)	(66 691)	(67 818)	1.6%	
Electric OM&A, including Accounting Changes	**462 952**	**480 717**	**485 755**	**541 740**	**551 675**	4.6%	
Less: Accounting Changes	(78 345)	(91 155)	(93 858)	(145 644)	(151 345)		
Electric OM&A, excluding Accounting Changes	**$ 384 607**	**$ 389 562**	**$ 391 897**	**$ 396 096**	**$ 400 330**	1.0%	
Year over Year % Change, including Accounting Changes		3.8%	1.0%	11.5%	1.8%	4.6%	
Year over Year % Change, excluding Accounting Changes		**1.3%**	**0.6%**	**1.1%**	**1.1%**	**1.0%**	

*Includes amounts capitalized through Overhead

Figure 5.4.13 above includes costs which are direct charged to the operations and maintenance activities of the Corporation (e.g. materials, contracted services, consulting, etc) as well as staff related costs, of which a portion is allocated to capital. Staff related costs, such as wages & salaries, benefits, travel, and motor vehicles, are costs associated with providing a pool of resources required for the operation, maintenance and capital construction activities of the Corporation. These costs are allocated to both capital projects and operating programs through the use of an hourly activity rate charged through the corporate time allocation system. Activity rates are calculated for work groups that perform a common set of functions.

In addition, under CGAAP a portion of costs (e.g. wages and salaries, benefits, office and administration, etc.) associated with corporate services and departmental support functions are also capitalized through an overhead rate. Under IFRS, only costs associated with the purchasing and accounts payable functions remain eligible for capitalization.

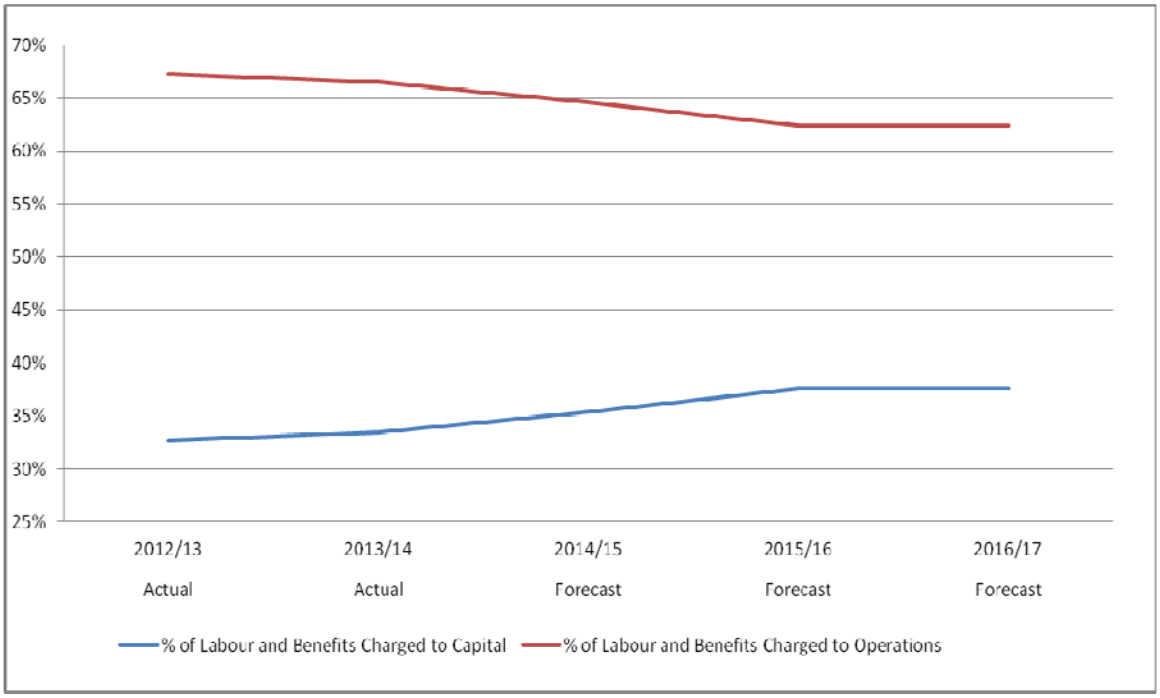
The figures below provide an analysis of the labour and benefit costs charged to capital and operations as a percentage of the total:

Figure 5.5.14 Labour & Benefits Charged Capital & Operations

MANITOBA HYDRO
LABOUR & BENEFITS CHARGED TO CAPITAL AND OPERATIONS

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Total Labour & Benefits	$ 658,082	$ 699,970	$ 724,993	$ 751,523	$ 766,109
Labour & Benefits Charged to Capital	215,491	234,510	256,588	282,335	287,969
Percentage of Labour and Benefits Charged to Capital	**33%**	**34%**	**35%**	**38%**	**38%**
Labour & Benefits Charged to Operations	442,591	465,460	468,405	469,188	478,140
Percentage of Labour and Benefits Charged to Operations	**67%**	**66%**	**65%**	**62%**	**62%**

Figure 5.5.15 Labour & Benefits Charged Capital & Operations %



As demonstrated, there is a steady growth in the capitalized component of the labor and benefit costs, ranging from 33% in 2012/13 to 38% in both 2015/16 and 2016/17. The increase of labor and expense capitalized in the forecast years reflects the growth in Manitoba Hydro's capital construction program required for Bipole III, Keeyask Generating Station, U.S. Transmission Interconnection, higher DSM requirements and increased investment in aging infrastructure. This growth is necessary to ensure the Corporation can continue to provide safe and reliable service.

The following provides explanations for cost elements that have significantly increased or decreased over the five year period as shown in Figure 5.4.13:

1) Wages & Salaries increased by an average of 3.5% primarily as a result of contract settlements with bargaining units and increases in numbers of equivalent full time employees (EFTs) primarily to support the growth in Manitoba Hydro's capital program. See section 4.0 Staffing Requirements to Manage Operations & Capital Investment.

2) Overtime increased by an average of 4.8% primarily as a result of protecting key in-service dates for capital projects such as Bipole III and the Keeyask Generating Station as well as increased costs due to the impact of union contract settlements.

3) Employee Benefits increased by an average of 5.3% primarily due to the decrease in the discount rate at the end of 2012/13 resulting in a significant experience loss on the pension liability resulting in increased amortization costs for 2013/14 and 2014/15 and an increase in the current service rate for 2013/14. IFRS changes, beginning in 2015/16, show a reduction of costs as the amortization of past service costs and actuarial gains and losses is eliminated and transitional adjustments related to pension and benefits are incorporated.

4) Labour & Benefits Charged to Capital increased by an average of 7.6% as the corporation commences construction of new generation & transmission projects such as Bipole III and Keeyask Generating Station, and addresses increased requirements for DSM programs, new customer connections, and aging infrastructure. In addition, contract negotiations with bargaining units and increased benefit costs have contributed to higher capitalized labor and expense costs.

5) Labour & Benefits and Other Costs Charged to Operations increased by an average of 2%, which is in line with inflation.

6) Employee Training & Safety increased by an average of 3.9% which reflects greater training costs related to I.T. development for projects such as Enterprise Asset Management (EAM) and new equipment training as well as greater fire retardant clothing requirements.

7) Consulting & Professional Fees increased by an average of 4.6% primarily related to new bio-physical monitoring costs incurred with the Wuskwatim Generating Station going into service in 2012/13.

8) Construction & Maintenance Services increased by an average of 3.6% due to a greater focus on the vegetation management program beginning in 2013/14 and higher external costs anticipated for generation maintenance activities. In addition, there is an increased requirement for brush clearing in 2014/15 which is reduced in 2015/16 as a result of a redeployment of those resources to focus on widening of right-of-ways primarily for Bipole III beginning in 2015/16.

9) Equipment Maintenance & Rentals increased by an average of 2.5% due to I.T. system implementations and rising costs of hardware and software maintenance contracts.

10) Customer & Public Relations decreased by an average of 5.5% as a result of lower corporate donations due to cost saving measures.

11) Office & Administration increased by an average of 3.2% as a result of rising postage costs and increased telecommunication costs to support the implementation of Mobile Workforce Management.

12) Miscellaneous Expense decreased by an average of 17.2% due to the expensing of capital project costs that were cancelled in 2012/13 and 2013/14, as well as lower forecasted radio license fees due to using fibre optic systems.

13) Operating Expense Recovery had no significant change overall in the 5 year period; however 2013/14 included a recovery of costs for the restoration work performed after the TCPL explosion and the assistance provided to Toronto Hydro after the December 2013 storm.

14) Strategic Initiative Funding was incorporated into IFF14 to provide funding for corporate programs outside of regular business unit operations that support corporate priorities. The Supply Chain Management Initiatives that are outlined in Section 5.14 of Tab 5 is an example of a corporate initiative for which funding has been provided.

15) Other Costs Charged to Capital increased by an average of 4.4% as the Corporation commences construction of new generation & transmission projects such as Bipole III and the Keeyask Generating Station, and addresses increased requirements for DSM programs, new customer connections, and aging infrastructure.

16) Capitalized Overhead decreased by 13.2% primarily in 2015/16 as a result of the transition to IFRS which does not allow for capitalization of training, service area costs, administrative & clerical support and divisional and department management costs.

6.0 ANALYSIS OF COSTS BY ORGANIZATONAL BUSINESS UNIT

Manitoba Hydro's organizational structure consists of 10 Business Units:

- President & CEO
- General Counsel & Corporate Secretary
- Human Resources & Corporate Services
- Corporate Relations
- Finance & Regulatory
- Generation Operations
- Major Capital Projects
- Transmission
- Customer Service & Distribution
- Customer Care & Energy Conservation

Each Business Unit is comprised of Divisions, Departments, and Cost Centres whose roles integrate to achieve the overall corporate strategic direction. These Business Units are accountable for their respective business objectives and operations and are the basis for developing detailed organization and staffing plans.

The following figure displays the organizational view of OM&A over the 5 year period:

Figure 5.5.16 OM&A by Business Unit

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)
President & CEO	$ 12,648	$ 10,887	$ 12,309	$ 12,469	$ 12,460	0.1%
General Counsel & Corporate Secretary	8,741	9,316	9,244	9,222	9,232	1.4%
Human Resources & Corporate Services	94,161	106,036	108,058	108,161	107,814	3.6%
Corporate Relations	9,730	8,918	10,059	10,008	10,033	1.0%
Finance & Regulatory	17,480	18,510	20,033	20,104	20,182	3.7%
Generation Operations	125,533	135,373	138,290	141,178	142,959	3.3%
Major Capital Projects	2,912	4,384	5,638	4,568	4,588	15.1%
Transmission	156,442	163,910	164,112	165,338	165,995	1.5%
Customer Service & Distribution	132,330	130,902	134,922	132,275	133,490	0.2%
Customer Care & Energy Conservation	49,624	55,353	58,361	56,364	56,837	3.6%
Business Unit	**$ 609,602**	**$ 643,590**	**$ 661,027**	**$ 659,687**	**$ 663,591**	**2.2%**

The average annual increase for the Business Units for the 5 year period remains close to the level of inflation (2.2%). All Business Units experienced cost increases in 2013/14 as a result of higher benefit costs primarily related to a change in the discount rate. In addition, all years reflect contract settlements with bargaining units which exceed the rate of inflation. These cost increases have been offset by various cost containment initiatives.

The Major Capital Projects Business Unit was formed in the fall of 2013 to centralize and establish a coordinated single point of contact for all major construction projects. The Business Unit is currently focused on the project management and construction of the Keeyask Generating Station, Bipole III, and Pointe du Bois Spillway Replacement, in addition to some smaller projects. In addition to benefit increases and contract settlements, the Major Capital Projects Business Unit's OM&A costs increased by an average of 15.1% primarily in 2013/14 and 2014/15 as a result administrative costs related to the creation of the new business unit that are no longer eligible for capitalization. In addition, temporary implementation costs related to the in-service of the Wuskwatim Generating Station occurred during these years but are no longer required in the forecast years.

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

DEPRECIATION RATES & DEPRECIATION STUDY

1.0 OVERVIEW

Depreciation expense is recognized on a straight-line basis over the estimated average remaining service life of assets, based upon depreciation studies conducted approximately every 5 years by the Corporation. Manitoba Hydro conducted a depreciation study in 2010 where new depreciation component groups were developed in anticipation of its transition to IFRS. Most recently, Manitoba Hydro completed a new study in October 2014 to develop Canadian GAAP (fiscal 2014/15) and IFRS compliant (fiscal 2015/16) depreciation rates. The following schedule provides a summary of the estimated changes to depreciation expense for the Electric Operations for fiscal 2014/15 (Canadian GAAP) and for the test years under IFRS, fiscal 2015/16 and 2016/17:

Figure 5.7.1 Depreciation Expense

	Depreciation Expense ($ millions)		
	2014/15	**2015/16**	**2016/17**
Change in service life - PP&E (net of contributions)	**(25)**	**(29)**	**(30)**
Overhead Ineligible for Capitalization			**(2)**
Elimination of Provision for Asset Removal	–	**(60)**	**(63)**
Change in Methodology (ELG)	–	**36**	**38**
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**

As with previous depreciation studies, an external consultant, Gannett Fleming Canada ULC, was engaged to review Manitoba Hydro's current depreciation practices, to provide advice on any changes necessary for compliance with IFRS, and to develop depreciation rates. Gannett Fleming performed an analysis of plant asset addition and retirement activity, as well as a peer review and discussions with operational and engineering staff to identify internal and external factors that impact the average useful service life and depreciation curve for each depreciable component. Please see the 2014 Depreciation Study for information about the scope, basis and methods used in this study.

The 2014 depreciation study is based on depreciable assets in service as of March 31, 2014. Manitoba Hydro has implement revised Canadian GAAP depreciation rates effective April 1, 2014 for fiscal 2014/15 and will implement IFRS compliant depreciation rates effective April 1, 2015 for fiscal 2015/16. The IFRS compliant depreciation rates will include the elimination of the provision for asset removal from depreciation rates as well as a change in the depreciation methodology to the Equal Life Group method.

The schedules provided on pages 6 – 13 of this Appendix provide a comparison of Manitoba Hydro's Canadian GAAP (CGAAP) depreciation rates (as determined in the 2010 depreciation study) to updated CGAAP and IFRS compliant depreciation rates. These schedules are followed by a letter from Gannett Fleming containing the depreciation rates to be used under CGAAP for 2014/15 and a report containing the depreciation rates to be used under IFRS for 2015/16. The significant changes in the 2014 depreciation study are discussed in the sections below.

2.0 REDUCTION IN DEPRECIATION UNDER CANADIAN GAAP (2014/15)

The $25 million annual reduction in depreciation expense under CGAAP for fiscal 2014/15 is the result of extensions to the service lives of select components, further reallocations of historical costs between existing and new component groups and reductions in the 2010 depreciation deficit balances for various components. Similar to the 2010 depreciation study, the results of the 2014 depreciation study reflect the findings of subject matter experts from Manitoba Hydro's operational areas who provided asset condition information based on recent year's condition assessment activities.

In general, Manitoba Hydro's continuous maintenance programs in combination with the Province's advantageous climatic conditions (eg. fewer freeze-thaw occurrences) have extended the service lives of many of its infrastructure-type assets longer than initially estimated. This is reflected in several depreciation rate decreases in the study.

Approximately $11 million of the $25 million overall reduction in depreciation expense pertains to an increase in the service lives for various assets in the Distribution, Communication, Motor Vehicle and Computer Software & Development components including: Overhead Serialized Equipment (35 to 45 years), Carrier Equipment (15 to 20 years), Heavy Trucks (15 to 19 years), and Operational System Major Software EMS/SCADA (6 to 7 years).

The remainder of the $25 million decrease in annual depreciation expense is primarily the net result of the following:

- Approximately $10 million of the reduction is the result of the re-allocation of historical costs within the HVDC asset components from assets with shorter service lives to assets with longer service lives. This re-allocation is the result of ongoing efforts by the Corporation to examine the records of certain assets so as to re-allocate costs amongst new and existing asset components;

- A further reduction of $5 million is the result of the drawdown of provisions built into 2010/11 depreciation rates for accumulated depreciation deficit balances that existed at the time of the 2010 depreciation study;
- These reductions are partially offset by a $6 million increase in the annual depreciation for the Hydraulic Generation component group as a result of shortening the amortization period on the asset retirement obligation for the decommissioning of the Point du Bois Spillway. The 2017 original retirement date of the spillway has been moved forward to 2015.

It should be noted that although Manitoba Hydro has been able to extend the service lives of many of its infrastructure type assets, many of these assets are nearing the end of their useful life. As such, the rate of installation of replacement assets will need to increase over the next 20 years so as to sustain existing levels of safety and reliability. Depreciation rate forecasts based on the 2014 study assume that Manitoba Hydro will continue to provide maintenance programs so as to achieve similar service lives from the replacement assets.

3.0 REDUCTION IN DEPRECIATION UNDER IFRS (2015/16 & 2016/17)

Upon its transition to IFRS effective April 1, 2015, Manitoba Hydro will eliminate negative salvage from depreciation rates in order to manage the overall impacts of IFRS to a net reduction to revenue requirement. Manitoba Hydro currently uses the ASL method under CGAAP, but will be changing to the ELG method upon transition to IFRS in order to be compliant with the financial reporting requirements. The net effect of Manitoba Hydro implementing these changes is a $24 million and $25 million reduction in annual depreciation expense in fiscal years 2015/16 and 2016/17, respectively. The break-down of the impact of these changes by asset category are presented in the following table:

Figure 5.7.2 Depreciation Expense

Depreciation (in millions of dollars)	2015-16 (IFRS)			2016-17 (IFRS)		
Electric Assets:	Provision for Asset Removal	Change to ELG	2015-16 IFRS Net Impact	Provision for Asset Removal	Change to ELG	2016-17 IFRS Net Impact
Generation	$ (13)	$ 8	$ (5)	$ (14)	$ 9	$ (5)
Transmission & Distribution	(42)	21	(21)	(45)	23	(22)
Communication	(1)	2	1	(1)	1	0
General Equipment	0	0	0	0	0	0
Other (e.g. Buildings, Software)	(1)	2	1	0	2	2
Wuskwatim Ltd. Partnership	(3)	3	0	(3)	3	0
Net increase (decrease) in revenue requirement	**$ (60)**	**$ 36**	**$ (24)**	**$ (63)**	**$ 38**	**$ (25)**

3.1 Eliminate Provision for Asset Removal Costs

Manitoba Hydro currently includes a provision in depreciation rates for asset removal costs. This is a regulatory practice applied under CGAAP by numerous Canadian Utilities. IFRS does not permit the practice of including a provision for the future removal costs of assets in deprecation unless there is a legal or constructive obligation to remove such assets. With the issuance of IFRS 14 *Regulatory Deferral Accounts*, Manitoba could continue to recognize this provision in depreciation rates as a regulatory deferral account. However, Manitoba Hydro has chosen to eliminate this practice upon its transition to IFRS in order to mitigate the impacts of other accounting changes to a net reduction in revenue requirement.

This is consistent with the findings of the PUB as outlined on page 18 of Order 43/13 (April 26, 2013):

> *"The Board accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial reporting Standards are implemented rather than during the test years"*

The estimated impact of this change for Manitoba Hydro's electric operations, as presented in Figure 5.7.2 is a decrease to depreciation expense of $60 and $63 million in fiscal 2015/16 and 2016/17, respectively.

3.2 Change to the ELG Method

IFRS is more specific than CGGAP regarding depreciation. Under IFRS, it is mandatory that items of material cost whose service life is different than other items in the group, be amortized separately. Effectively, if the separate depreciation of an item would have a material impact on net income, that item should be depreciated separately. This requirement is not mandatory under CGAAP.

The ELG method calculates depreciation with consideration of the different expected service lives for each of the assets within a group. Every significant asset in the class is depreciated over its own expected service life and is therefore expected to be fully depreciated (not over or under depreciated) when removed from service. This will result in an increase in depreciation expense of $36 million in 2015/16 and $38 million in 2016/17 as presented in figure 5.7.2.

The following provides the schedule of depreciation rates for Electric operations, under ASL and ELG depreciation methods.

Depreciation Rate Schedules (Electric operations)

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
HYDRAULIC GENERATION				
GREAT FALLS				
DAMS, DYKES AND WEIRS	125	1.28	1.32	1.12
POWERHOUSE	125	1.27	1.28	1.07
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.59	1.50	1.35
WATER CONTROL SYSTEMS	65	2.07	1.52	1.35
ROADS AND SITE IMPROVEMENTS	50	2.33	2.42	2.42
TURBINES AND GENERATORS	60	1.82	2.25	2.03
GOVERNORS AND EXCITATION SYSTEM	50	2.11	2.25	2.06
LICENCE RENEWAL	50	2.00	2.04	2.04
A/C ELECTRICAL POWER SYSTEMS	55	2.10	1.84	1.67
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.43	3.86	3.79
AUXILIARY STATION PROCESSES	50	2.59	2.03	2.10
SUPPORT BUILDINGS	65	1.73	1.69	1.36
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
POINTE DU BOIS - Original				
DAMS, DYKES AND WEIRS	125	3.63	3.10	2.70
POWERHOUSE	125	4.39	2.94	2.55
POWERHOUSE RENOVATIONS	40	5.24	4.10	3.71
SPILLWAY	80	10.76	84.53	73.37
WATER CONTROL SYSTEMS	65	3.35	2.11	1.73
ROADS AND SITE IMPROVEMENTS	50	3.36	4.09	3.80
TURBINES AND GENERATORS	60	4.04	2.84	2.44
GOVERNORS AND EXCITATION SYSTEM	50	5.24	4.02	3.68
LICENCE RENEWAL	50	4.76	3.85	3.85
A/C ELECTRICAL POWER SYSTEMS	55	4.58	3.16	2.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.12	4.30	4.26
AUXILIARY STATION PROCESSES	50	4.03	3.71	3.59
SUPPORT BUILDINGS	65	2.93	2.99	2.59
SUPPORT BUILDING RENOVATIONS	20	5.50	4.47	3.84
POINTE DU BOIS - New				
DAMS, DYKES AND WEIRS	125	-	0.91	0.85
SPILLWAY	80	1.47	1.37	1.49
WATER CONTROL SYSTEMS	65	-	1.69	1.64
ROADS AND SITE IMPROVEMENTS	50	-	2.20	2.36
A/C ELECTRICAL POWER SYSTEMS	55	-	2.40	1.94
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	-	4.40	4.54
AUXILIARY STATION PROCESSES	50	-	2.20	3.01
SUPPORT BUILDINGS	65	-	1.69	1.65
SUPPORT BUILDING RENOVATIONS	20	-	5.50	5.00
SEVEN SISTERS				
DAMS, DYKES AND WEIRS	125	1.03	1.06	0.90
POWERHOUSE	125	0.90	0.91	0.74
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.17	1.36	1.17
WATER CONTROL SYSTEMS	65	1.80	1.25	1.02
ROADS AND SITE IMPROVEMENTS	50	1.84	1.78	1.30
TURBINES AND GENERATORS	60	1.64	1.84	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.00	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.91	1.74	1.56
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	3.73	3.80	3.44
AUXILIARY STATION PROCESSES	50	2.13	1.91	2.03
SUPPORT BUILDINGS	65	1.74	1.65	1.52
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
SLAVE FALLS				
DAMS, DYKES AND WEIRS	125	1.69	1.71	1.54
POWERHOUSE	125	1.58	1.59	1.43
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.87	1.82	1.74
WATER CONTROL SYSTEMS	65	2.18	1.77	1.65
ROADS AND SITE IMPROVEMENTS	50	2.20	2.30	2.36
TURBINES AND GENERATORS	60	1.79	1.91	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	2.00	1.91
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.72	4.42	4.56
AUXILIARY STATION PROCESSES	50	2.73	2.34	2.70
SUPPORT BUILDINGS	65	1.81	2.01	1.89
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
PINE FALLS				
DAMS, DYKES AND WEIRS	125	1.17	1.23	1.12
POWERHOUSE	125	0.83	0.83	0.71
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.60	1.50	1.49
WATER CONTROL SYSTEMS	65	1.95	1.28	1.06
ROADS AND SITE IMPROVEMENTS	50	1.81	1.68	1.61
TURBINES AND GENERATORS	60	1.47	1.62	1.37
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.06	1.83	1.58
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.25	4.17	4.04
AUXILIARY STATION PROCESSES	50	2.54	1.78	1.81
SUPPORT BUILDINGS	65	1.61	1.62	1.56
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	78	1.17	1.28	1.28
MCARTHUR FALLS				
DAMS, DYKES AND WEIRS	125	0.91	1.12	1.00
POWERHOUSE	125	0.83	0.84	0.72
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.19	1.19	0.97
WATER CONTROL SYSTEMS	65	2.06	1.37	1.25
ROADS AND SITE IMPROVEMENTS	50	1.99	1.94	1.71
TURBINES AND GENERATORS	60	1.06	1.35	0.94
GOVERNORS AND EXCITATION SYSTEM	50	2.10	2.08	1.94
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.90	1.72	1.32
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.29	3.62	2.74
AUXILIARY STATION PROCESSES	50	2.58	1.82	1.85
SUPPORT BUILDINGS	65	1.63	1.73	1.67
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
KELSEY				
DAMS, DYKES AND WEIRS	125	1.05	1.13	1.03
POWERHOUSE	125	0.89	1.18	1.08
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.34	1.71	1.58
WATER CONTROL SYSTEMS	65	2.09	1.70	1.61
ROADS AND SITE IMPROVEMENTS	50	2.05	2.44	2.30
TURBINES AND GENERATORS	60	1.68	1.90	1.85
GOVERNORS AND EXCITATION SYSTEM	50	2.14	2.25	2.17
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.03	2.11	2.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.67	4.62
AUXILIARY STATION PROCESSES	50	2.63	2.19	2.31
SUPPORT BUILDINGS	65	1.67	1.79	1.73
SUPPORT BUILDING RENOVATIONS	20	4.98	4.98	4.44
GRAND RAPIDS				
DAMS, DYKES AND WEIRS	125	0.98	1.01	0.90
POWERHOUSE	125	0.91	0.92	0.81
POWERHOUSE RENOVATIONS	40	4.40	2.55	2.28
SPILLWAY	80	1.30	1.28	1.15
WATER CONTROL SYSTEMS	65	1.79	1.10	0.99
ROADS AND SITE IMPROVEMENTS	50	1.68	1.63	1.21
TURBINES AND GENERATORS	60	1.64	1.82	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.13	2.21	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.07	1.84	1.66
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.08	3.90	2.49
AUXILIARY STATION PROCESSES	50	2.62	2.02	2.29
SUPPORT BUILDINGS	65	1.66	1.69	1.60
SUPPORT BUILDING RENOVATIONS	20	5.50	5.67	5.00
COMMUNITY DEVELOPMENT COSTS ***	79	1.16	1.21	1.21
KETTLE				
DAMS, DYKES AND WEIRS	125	0.86	0.86	0.78
POWERHOUSE	125	0.87	0.86	0.79
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.33	1.26	1.16
WATER CONTROL SYSTEMS	65	1.55	0.99	0.89
ROADS AND SITE IMPROVEMENTS	50	2.14	2.20	2.31
TURBINES AND GENERATORS	60	1.48	1.90	1.73
GOVERNORS AND EXCITATION SYSTEM	50	1.66	2.14	1.92
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.04	2.04	1.96
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.11	4.20	3.37
AUXILIARY STATION PROCESSES	50	2.44	1.82	1.86
SUPPORT BUILDINGS	65	1.46	1.75	1.70
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LAURIE RIVER				
DAMS, DYKES AND WEIRS	125	3.47	3.20	2.70
POWERHOUSE	125	4.25	3.89	3.40
POWERHOUSE RENOVATIONS	40	5.00	5.24	4.76
SPILLWAY	80	3.88	3.44	2.96
WATER CONTROL SYSTEMS	65	3.84	3.52	3.03
ROADS AND SITE IMPROVEMENTS	50	4.01	3.69	3.23
TURBINES AND GENERATORS	60	4.49	4.11	3.62
GOVERNORS AND EXCITATION SYSTEM	50	4.70	4.29	3.81
LICENCE RENEWAL	50	4.55	4.76	4.76
A/C ELECTRICAL POWER SYSTEMS	55	4.08	3.63	3.15
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	7.23	6.28	5.15
AUXILIARY STATION PROCESSES	50	4.30	3.73	3.31
SUPPORT BUILDINGS	65	3.75	3.36	2.87
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
JENPEG				
DAMS, DYKES AND WEIRS	125	0.92	0.91	0.84
POWERHOUSE	125	0.89	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.48
SPILLWAY	80	1.42	1.35	1.28
WATER CONTROL SYSTEMS	65	2.02	1.24	1.07
ROADS AND SITE IMPROVEMENTS	50	2.12	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.89	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.05	1.81	1.53
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.53	4.15	3.39
AUXILIARY STATION PROCESSES	50	2.66	1.92	2.06
SUPPORT BUILDINGS	65	1.67	1.69	1.61
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
LAKE WINNIPEG REGULATION				
DAMS, DYKES AND WEIRS	125	0.82	0.82	0.77
LICENCE RENEWAL	50	2.00	2.02	2.02
COMMUNITY DEVELOPMENT COSTS	85	0.94	1.18	1.18
CHURCHILL RIVER DIVERSION				
DAMS, DYKES AND WEIRS	125	0.88	0.88	0.83
SPILLWAY	80	1.47	1.39	1.32
WATER CONTROL SYSTEMS	65	2.21	1.17	1.00
ROADS AND SITE IMPROVEMENTS	50	2.21	2.11	1.78
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	1.88	1.57
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.82	4.78	2.36
AUXILIARY STATION PROCESSES	50	2.75	1.97	2.11
SUPPORT BUILDINGS	65	1.69	1.71	1.66
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	90	0.93	1.07	1.07

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LONG SPRUCE				
DAMS, DYKES AND WEIRS	125	0.90	0.90	0.83
POWERHOUSE	125	0.90	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.43	1.36	1.30
WATER CONTROL SYSTEMS	65	2.04	0.99	0.78
ROADS AND SITE IMPROVEMENTS	50	2.10	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.88	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.19	2.18	2.08
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.09	1.79	1.51
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.37	4.37	3.87
AUXILIARY STATION PROCESSES	50	2.63	1.60	1.53
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.90
LIMESTONE				
DAMS, DYKES AND WEIRS	125	0.90	0.91	0.85
POWERHOUSE	125	0.91	0.91	0.85
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.45	1.37	1.37
WATER CONTROL SYSTEMS	65	2.17	1.39	1.28
ROADS AND SITE IMPROVEMENTS	50	2.17	2.14	2.03
TURBINES AND GENERATORS	60	1.68	1.90	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.17	2.15	1.96
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.17	1.89	1.73
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.67	4.16	3.48
AUXILIARY STATION PROCESSES	50	2.71	1.78	1.80
SUPPORT BUILDINGS	65	1.68	1.71	1.63
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.89
WUSKWATIM				
DAMS, DYKES AND WEIRS	125	0.88	0.91	0.87
POWERHOUSE	125	0.88	0.91	0.87
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.47	1.36	1.46
WATER CONTROL SYSTEMS	65	2.20	1.68	1.62
ROADS AND SITE IMPROVEMENTS	50	2.20	2.19	2.32
TURBINES AND GENERATORS	60	1.69	1.83	1.78
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.19	2.12
A/C ELECTRICAL POWER SYSTEMS	55	2.20	1.99	1.92
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.78	4.24	4.39
AUXILIARY STATION PROCESSES	50	2.75	2.13	2.93
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
INFRASTRUCTURE SUPPORTING GENERATION				
PROVINCIAL ROADS	50	2.30	2.49	2.21
TOWN SITE BUILDING	55	1.71	2.12	2.03
TOWN SITE BUILDINGS RENOVATIONS	20	5.94	5.30	5.00
TOWN SITE OTHER INFRASTRUCTURE	45	2.49	3.11	2.93

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
THERMAL GENERATION				
BRANDON UNIT 5 (COAL)				
POWERHOUSE	75	3.87	4.52	4.50
POWERHOUSE RENOVATIONS	40	10.00	15.88	15.88
ROADS AND SITE IMPROVEMENTS	50	4.56	5.37	5.36
THERMAL TURBINES AND GENERATORS	60	5.03	5.73	5.72
GOVERNORS AND EXCITATION SYSTEM	50	5.07	5.51	5.52
STEAM GENERATOR AND AUXILIARIES	60	3.93	4.06	4.05
LICENCE RENEWAL	50	10.00	14.81	14.81
A/C ELECTRICAL POWER SYSTEMS	55	4.06	4.65	4.64
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.41	4.44	4.41
AUXILIARY STATION PROCESSES	50	4.67	5.36	5.37
SUPPORT BUILDINGS	65	4.25	5.97	5.97
SUPPORT BUILDING RENOVATIONS	20	10.00	16.67	16.67
BRANDON UNITS 6 AND 7				
POWERHOUSE	75	1.65	1.38	1.26
POWERHOUSE RENOVATIONS	40	4.40	2.72	2.46
THERMAL TURBINES AND GENERATORS	60	2.12	1.70	1.64
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
COMBUSTION TURBINE	25	4.05	3.87	3.66
LICENCE RENEWAL	50	2.00	2.00	2.00
COMBUSTION TURBINE OVERHAULS	15	11.00	7.33	6.67
A/C ELECTRICAL POWER SYSTEMS	55	2.12	1.88	1.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.52	4.63
AUXILIARY STATION PROCESSES	50	2.64	1.91	2.10
SELKIRK				
POWERHOUSE	75	0.93	0.76	0.79
POWERHOUSE RENOVATIONS	40	4.00	2.45	2.45
ROADS AND SITE IMPROVEMENTS	50	1.35	1.34	1.42
THERMAL TURBINES AND GENERATORS	60	1.46	1.09	1.18
GOVERNORS AND EXCITATION SYSTEM	50	2.00	1.13	1.30
STEAM GENERATOR AND AUXILIARIES	60	1.34	1.49	1.66
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.21	1.06	1.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	2.41	2.11	2.40
AUXILIARY STATION PROCESSES	50	1.64	1.19	1.44
SUPPORT BUILDINGS	65	1.06	1.06	1.13
SUPPORT BUILDING RENOVATIONS	20	5.00	5.00	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
DIESEL GENERATION				
BUILDINGS	25	2.57	3.15	3.17
BUILDING RENOVATIONS	15	5.14	6.67	6.67
ENGINES AND GENERATORS - OVERHAULS	4	20.00	25.00	25.00
ENGINES AND GENERATORS	22	1.88	2.24	2.73
ACCESSORY STATION EQUIPMENT	20	3.07	3.70	3.67
FUEL STORAGE AND HANDLING	25	2.28	2.37	2.60
TRANSMISSION				
ROADS, TRAILS AND BRIDGES	50	2.51	2.19	2.18
METAL TOWERS AND CONCRETE POLES	85	1.51	1.54	1.23
POLES AND FIXTURES	55	2.49	2.48	1.80
GROUND LINE TREATMENT	10	10.00	10.00	10.00
OVERHEAD CONDUCTOR AND DEVICES	80	1.62	1.27	1.10
UNDERGROUND CABLE AND DEVICES	45	2.23	1.96	1.81
COMMUNITY DEVELOPMENT COSTS ***	79	1.27	1.27	1.27
SUBSTATIONS				
BUILDINGS	65	1.49	1.47	1.46
BUILDING RENOVATIONS	20	5.00	5.00	5.00
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	2.10	1.95	1.76
POLES AND FIXTURES	45	3.25	3.01	2.39
POWER TRANSFORMERS	50	2.21	2.44	2.43
OTHER TRANSFORMERS	50	3.09	2.29	2.26
INTERRUPTING EQUIPMENT	50	2.41	2.52	2.31
OTHER STATION EQUIPMENT	45	2.54	2.47	2.20
ELECTRONIC EQUIPMENT AND BATTERIES	25	4.76	3.81	3.90
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	65	1.68	1.80	1.52
SYNCHRONOUS CONDENSER OVERHAULS	15	7.43	7.15	5.58
HVDC CONVERTER EQUIPMENT	30	4.13	3.22	2.61
HVDC SERIALIZED EQUIPMENT	30	4.18	3.04	2.07
HVDC ACCESSORY STATION EQUIPMENT	36	2.85	2.98	2.67
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	25	4.66	3.10	2.27
DISTRIBUTION				
CONCRETE DUCTLINE AND MANHOLES	75	2.29	2.23	2.25
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENTS	30	2.08	3.66	3.70
METAL TOWERS	60	1.99	2.10	1.87
POLES AND FIXTURES	65	2.10	1.96	1.58
GROUND LINE TREATMENT	12	9.58	7.39	7.39
OVERHEAD CONDUCTOR AND DEVICES	60	1.98	2.24	1.80
UNDERGROUND CABLE AND DEVICES - 66 KV	60	1.48	1.72	2.07
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	1.69	1.70	1.83
UNDERGROUND CABLE AND DEVICES - SECONDARY	44	2.21	2.27	2.31
SERIALIZED EQUIPMENT - OVERHEAD	45	2.86	2.28	2.10
DSC - HIGH VOLTAGE TRANSFORMERS	50	2.19	2.34	2.34
SERIALIZED EQUIPMENT - UNDERGROUND	42	2.62	2.60	2.40
ELECTRONIC EQUIPMENT	10	10.00	10.53	10.53
SERVICES	35	4.38	2.92	1.89
STREET LIGHTING	45	3.04	2.56	2.20

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
METERS				
METERS - ELECTRONIC	15	6.10	9.61	10.52
METERS - ANALOG	26	13.54	3.84	4.21
METERING EXCHANGES	15	6.67	6.67	6.67
METERING TRANSFORMERS	50	2.20	1.80	2.12
COMMUNICATION				
BUILDINGS	65	1.67	1.41	1.48
BUILDING RENOVATIONS	20	5.67	4.95	4.58
BUILDING - SYSTEM CONTROL CENTRE	75	1.68	1.39	1.40
COMMUNICATION TOWERS	60	1.82	1.82	2.01
FIBRE OPTIC AND METALLIC CABLE	35	3.06	3.12	3.45
CARRIER EQUIPMENT	20	7.68	4.74	4.90
OPERATIONAL IT EQUIPMENT	5	22.97	21.00	20.00
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8	10.24	18.56	16.64
OPERATIONAL DATA NETWORK	8	14.10	13.13	12.50
POWER SYSTEM CONTROL	15	11.16	5.63	5.50
MOTOR VEHICLES				
PASSENGER VEHICLES	11	11.09	7.03	7.59
LIGHT TRUCKS	12	7.85	7.16	7.54
HEAVY TRUCKS	19	5.83	4.68	5.01
CONSTRUCTION EQUIPMENT	23	5.27	2.77	3.23
LARGE SOFT-TRACK EQUIPMENT	27	4.28	2.96	3.79
TRAILERS	35	1.94	2.38	2.91
MISCELLANEOUS VEHICLES	13	5.93	4.90	6.60
BUILDINGS				
BUILDINGS - GENERAL	65	1.59	1.65	1.73
BUILDING RENOVATIONS	20	7.14	5.59	5.00
BUILDING - 360 PORTAGE - CIVIL	100	1.00	1.00	1.06
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	2.21	2.23	2.56
LEASEHOLD IMPROVEMENTS - SONY PLACE	10	10.00	10.00	10.00
GENERAL EQUIPMENT				
TOOLS, SHOP AND GARAGE EQUIPMENT	15	7.74	6.48	6.48
COMPUTER EQUIPMENT	5	28.48	20.00	20.00
OFFICE FURNITURE AND EQUIPMENT	20	4.81	5.00	5.00
HOT WATER TANKS	6	21.20	16.67	16.67
EASEMENTS				
EASEMENTS	75	1.28	1.33	1.33
COMPUTER SOFTWARE AND DEVELOPMENT				
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	11	9.47	8.75	8.82
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10.00	9.13	9.13
COMPUTER SOFTWARE - GENERAL	5	19.76	20.00	20.00
COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	5	13.93	27.31	27.31
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	7	23.35	8.06	9.33

Gannett Fleming

Excellence Delivered ***As Promised***

January 14, 2015

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba
T3C 0G8

Attention: Mr. Darren Rainkie
Vice-President, Finance and Regulatory

Ladies and Gentlemen:

Pursuant to your request, we have calculated depreciation rates based on your original cost as of March 31, 2014 using the depreciation calculation procedures that were approved in your last depreciation study, namely the use of the Average Service Life (”ASL”) procedure and incorporation of estimated net salvage percentages. The attached schedules provide a summary of the depreciation rates related to the electric generation, transmission, substation, distribution and general plant assets of Manitoba Hydro and the Wuskwatim Power Limited Partnership as of March 31, 2014.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of March 31, 2014. The depreciation rates are based on the average service life estimates and interim survivor curve determinations as recently completed in the full depreciation study report. The net salvage percentages used in the enclosed schedules of depreciation rates are consistent with the percentages used in the 2010 Depreciation Study.

Gannett Fleming has calculated and is providing these requested schedules of depreciation rates in order to provide continuity from the last depreciation study, through the transition to the depreciation rates as provided in the recently completed Gannett Fleming Depreciation Study report.

Gannett Fleming Canada ULC

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As the attached schedules are a work product of Gannett Fleming, we ask that this cover letter be provided any time that the attached schedules are distributed. Gannett Fleming does, however, authorize the distribution of the electronic version of the attached schedules.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK:hac
Project: 058390:400

/Attachments - 4

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	GENERATION									
	HYDRAULIC GENERATION									
	GREAT FALLS									
1105A	DAMS, DYKES AND WEIRS	2063	125-R4	(10)	17,345,473	243,117	1.40	(13,895)	229,222	1.32
1105B	POWERHOUSE	2063	125-R4	(10)	7,990,993	111,012	1.39	(8,594)	102,418	1.28
1105C	POWERHOUSE RENOVATIONS	2063	40-SQ	(10)	47,039	1,294	2.75	(39)	1,255	2.67
1105D	SPILLWAY	2063	80-R3	(10)	9,676,327	153,290	1.58	(8,096)	145,194	1.50
1105E	WATER CONTROL SYSTEMS	2063	65-R4	(10)	24,245,253	447,637	1.85	(77,935)	369,702	1.52
1105F	ROADS AND SITE IMPROVEMENTS	2063	50-R3	(10)	935,986	22,652	2.42	6	22,658	2.42
1105G	TURBINES AND GENERATORS	2063	60-S3	(10)	33,818,312	707,412	2.09	53,892	761,304	2.25
1105H	GOVERNORS AND EXCITATION SYSTEM	2063	50-R4	(10)	1,154,724	26,472	2.29	(490)	25,982	2.25
1105L	LICENCE RENEWAL	2063	50-SQ	0						2.04 *
1105P	A/C ELECTRICAL POWER SYSTEMS	2063	55-R4	(10)	9,493,088	189,489	2.00	(15,235)	174,254	1.84
1105Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2063	25-S2	(10)	19,506,209	836,830	4.29	(84,645)	752,185	3.86
1105R	AUXILIARY STATION PROCESSES	2063	50-R2	(10)	10,221,178	240,431	2.35	(32,749)	207,682	2.03
1105X	SUPPORT BUILDINGS	2063	65-S3	(10)	1,495,253	27,532	1.84	(2,189)	25,343	1.69
1105W	SUPPORT BUILDING RENOVATIONS	2063	20-SQ	(10)	18,859	1,037	5.50		1,037	5.50 **
	TOTAL GREAT FALLS				**135,948,694**	**3,008,205**	**2.21**	**(189,969)**	**2,818,236**	**2.07**
	POINTE DU BOIS									
1110A	DAMS, DYKES AND WEIRS	2040	125-R4	(10)	20,718,888	774,421	3.74	(132,581)	641,840	3.10
1110B	POWERHOUSE	2040	125-R4	(10)	6,054,784	213,317	3.52	(35,198)	178,119	2.94
1110C	POWERHOUSE RENOVATIONS	2040	40-SQ	(10)	1,897,782	79,291	4.18	(1,404)	77,887	4.10
1110D	SPILLWAY - ORIGINAL	2015	80-R3	(10)	7,797,851	4,844,008	62.12	1,747,665	6,591,673	84.53
1110E	WATER CONTROL SYSTEMS	2040	65-R4	(10)	4,466,812	146,086	3.27	(51,625)	94,461	2.11
1110F	ROADS AND SITE IMPROVEMENTS	2040	50-R3	(10)	1,055,707	43,303	4.10	(130)	43,173	4.09
1110G	TURBINES AND GENERATORS	2040	60-S3	(10)	31,899,060	1,140,264	3.57	(234,880)	905,385	2.84
1110H	GOVERNORS AND EXCITATION SYSTEM	2040	50-R4	(10)						4.02 *
1110L	LICENCE RENEWAL	2040	50-SQ	0						3.85 *
1110P	A/C ELECTRICAL POWER SYSTEMS	2040	55-R4	(10)	7,759,986	289,310	3.73	(44,309)	245,001	3.16
1110Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2040	25-S2	(10)	1,037,485	49,371	4.76	(4,723)	44,648	4.30
1110R	AUXILIARY STATION PROCESSES	2040	50-R2	(10)	5,357,425	213,550	3.99	(14,885)	198,665	3.71
1110X	SUPPORT BUILDINGS	2040	65-S3	(10)	882,202	30,894	3.50	(4,552)	26,343	2.99
1110W	SUPPORT BUILDING RENOVATIONS	2040	20-SQ	(10)	347,164	19,094	5.50	(3,575)	15,519	4.47
	TOTAL POINTE DU BOIS				**89,275,145**	**7,842,909**	**8.79**	**1,219,803**	**9,062,712**	**10.15**
	POINTE DU BOIS - NEW									
1111A	DAMS, DYKES AND WEIRS		125-R4	(10)						0.91 *
1111D	SPILLWAY		80-R3	(10)						1.37 *
1111E	WATER CONTROL SYSTEMS		65-R4	(10)						1.69 *
1111F	ROADS AND SITE IMPROVEMENTS		50-R3	(10)						2.20 *
1111P	A/C ELECTRICAL POWER SYSTEMS		55-R4	(10)						2.40 *
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	(10)						4.40 *
1111R	AUXILIARY STATION PROCESSES		50-R2	(10)						2.20 *
1111X	SUPPORT BUILDINGS		65-S3	(10)						1.69 *
1111W	SUPPORT BUILDING RENOVATIONS		20-SQ	(10)						5.50
	TOTAL POINTE DU BOIS - NEW				**0**	**0**		**0**	**0**	
	SEVEN SISTERS									
1115A	DAMS, DYKES AND WEIRS	2072	125-R4	(10)	31,926,879	398,089	1.25	(60,063)	338,026	1.06
1115B	POWERHOUSE	2072	125-R4	(10)	13,653,945	159,444	1.17	(34,962)	124,483	0.91
1115C	POWERHOUSE RENOVATIONS	2072	40-SQ	(10)	578,473	15,908	2.75	(473)	15,435	2.67
1115D	SPILLWAY	2072	80-R3	(10)	2,940,065	44,304	1.51	(4,426)	39,878	1.36
1115E	WATER CONTROL SYSTEMS	2072	65-R4	(10)	4,520,291	78,670	1.74	(22,029)	56,641	1.25
1115F	ROADS AND SITE IMPROVEMENTS	2072	50-R3	(10)	205,641	4,553	2.21	(887)	3,666	1.78
1115G	TURBINES AND GENERATORS	2072	60-S3	(10)	54,449,323	1,052,524	1.93	(52,245)	1,000,279	1.84
1115H	GOVERNORS AND EXCITATION SYSTEM	2072	50-R4	(10)	290,552	6,455	2.22	(17)	6,438	2.22
1115L	LICENCE RENEWAL	2072	50-SQ	0						2.00 *
1115P	A/C ELECTRICAL POWER SYSTEMS	2072	55-R4	(10)	11,924,230	240,665	2.02	(32,975)	207,690	1.74
1115Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2072	25-S2	(10)	4,960,007	218,240	4.40	(29,894)	188,347	3.80
1115R	AUXILIARY STATION PROCESSES	2072	50-R2	(10)	8,512,853	193,196	2.27	(30,543)	162,653	1.91
1115X	SUPPORT BUILDINGS	2072	65-S3	(10)	608,294	11,131	1.83	(1,099)	10,032	1.65
1115W	SUPPORT BUILDING RENOVATIONS	2072	20-SQ	(10)						5.50 *
	TOTAL SEVEN SISTERS				**134,570,553**	**2,423,179**	**1.80**	**(269,612)**	**2,153,567**	**1.60**

Appendix 5.6 - Attachment 1

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	SLAVE FALLS									
1120A	DAMS, DYKES AND WEIRS	2072	125-R4	(10)	954,684	16,443	1.72	(76)	16,367	1.71
1120B	POWERHOUSE	2072	125-R4	(10)	45,692,194	735,088	1.61	(7,830)	727,258	1.59
1120C	POWERHOUSE RENOVATIONS	2072	40-SQ	(10)						2.75 *
1120D	SPILLWAY	2072	80-R3	(10)	1,241,273	22,802	1.84	(151)	22,651	1.82
1120E	WATER CONTROL SYSTEMS	2072	65-R4	(10)	318,933	5,878	1.84	(233)	5,645	1.77
1120F	ROADS AND SITE IMPROVEMENTS	2072	50-R3	(10)	37,971,797	861,107	2.27	11,260	872,367	2.30
1120G	TURBINES AND GENERATORS	2072	60-S3	(10)	12,246,529	235,165	1.92	(739)	234,426	1.91
1120H	GOVERNORS AND EXCITATION SYSTEM	2072	50-R4	(10)	336,652	7,517	2.23	(47)	7,470	2.22
1120L	LICENCE RENEWAL	2072	50-SQ	0						2.00 *
1120P	A/C ELECTRICAL POWER SYSTEMS	2072	55-R4	(10)	21,631,850	440,352	2.04	(6,911)	433,441	2.00
1120Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2072	25-S2	(10)	4,446,295	195,637	4.40	944	196,581	4.42
1120R	AUXILIARY STATION PROCESSES	2072	50-R2	(10)	5,288,154	123,164	2.33	804	123,968	2.34
1120X	SUPPORT BUILDINGS	2072	65-S3	(10)	3,306,577	60,389	1.83	6,165	66,554	2.01
1120W	SUPPORT BUILDING RENOVATIONS	2072	20-SQ	(10)						5.50 *
	TOTAL SLAVE FALLS				**133,434,938**	**2,703,542**	**2.03**	**3,184**	**2,706,726**	**2.03**
	PINE FALLS									
1125A	DAMS, DYKES AND WEIRS	2092	125-R4	(10)	18,301,512	230,068	1.26	(4,452)	225,616	1.23
1125B	POWERHOUSE	2092	125-R4	(10)	10,060,843	95,592	0.95	(11,898)	83,694	0.83
1125C	POWERHOUSE RENOVATIONS	2092	40-SQ	(10)	121,809	3,350	2.75	(102)	3,249	2.67
1125D	SPILLWAY	2092	80-R3	(10)	93,376	1,413	1.51	(14)	1,399	1.50
1125E	WATER CONTROL SYSTEMS	2092	65-R4	(10)	3,660,833	62,025	1.69	(15,261)	46,764	1.28 ****
1125F	ROADS AND SITE IMPROVEMENTS	2092	50-R3	(10)	1,180,058	25,961	2.20	(6,182)	19,779	1.68
1125G	TURBINES AND GENERATORS	2092	60-S3	(10)	9,318,154	171,175	1.84	(19,911)	151,264	1.62
1125H	GOVERNORS AND EXCITATION SYSTEM	2092	50-R4	(10)						2.20 *
1125L	LICENCE RENEWAL	2092	50-SQ	0						2.00 *
1125P	A/C ELECTRICAL POWER SYSTEMS	2092	55-R4	(10)	5,096,978	102,041	2.00	(8,706)	93,335	1.83
1125Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2092	25-S2	(10)	3,881,573	170,789	4.40	(8,842)	161,947	4.17
1125R	AUXILIARY STATION PROCESSES	2092	50-R2	(10)	3,976,778	87,500	2.20	(16,764)	70,736	1.78
1125X	SUPPORT BUILDINGS	2092	65-S3	(10)	336,412	5,699	1.69	(236)	5,463	1.62
1125W	SUPPORT BUILDING RENOVATIONS	2092	20-SQ	(10)						5.50 *
1125Z	COMMUNITY DEVELOPMENT COSTS ***	2092	78-SQ	0	26,531,770	339,607	1.28		339,607	1.28 **
	TOTAL PINE FALLS				**82,560,097**	**1,295,220**	**1.57**	**(92,367)**	**1,202,853**	**1.46**
	MCARTHUR FALLS									
1130A	DAMS, DYKES AND WEIRS	2095	125-R4	(10)	6,837,356	78,708	1.15	(2,370)	76,338	1.12
1130B	POWERHOUSE	2095	125-R4	(10)	9,358,105	87,154	0.93	(8,944)	78,210	0.84
1130C	POWERHOUSE RENOVATIONS	2095	40-SQ	(10)	405,461	11,150	2.75	(338)	10,812	2.67
1130D	SPILLWAY	2095	80-R3	(10)	2,417,504	33,328	1.38	(4,574)	28,754	1.19
1130E	WATER CONTROL SYSTEMS	2095	65-R4	(10)	11,703,203	198,252	1.69	(37,995)	160,257	1.37
1130F	ROADS AND SITE IMPROVEMENTS	2095	50-R3	(10)	235,262	5,176	2.20	(609)	4,567	1.94
1130G	TURBINES AND GENERATORS	2095	60-S3	(10)	5,379,618	98,842	1.84	(26,050)	72,792	1.35
1130H	GOVERNORS AND EXCITATION SYSTEM	2095	50-R4	(10)	119,315	2,625	2.20	(140)	2,485	2.08
1130L	LICENCE RENEWAL	2095	50-SQ	0						2.00 *
1130P	A/C ELECTRICAL POWER SYSTEMS	2095	55-R4	(10)	2,521,761	50,486	2.00	(7,029)	43,457	1.72
1130Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2095	25-S2	(10)	1,275,876	52,286	4.10	(6,064)	46,222	3.62
1130R	AUXILIARY STATION PROCESSES	2095	50-R2	(10)	3,616,031	79,553	2.20	(13,782)	65,771	1.82
1130X	SUPPORT BUILDINGS	2095	65-S3	(10)						1.73
1130W	SUPPORT BUILDING RENOVATIONS	2095	20-SQ	(10)						5.50
	TOTAL MCARTHUR FALLS				**43,869,489**	**697,560**	**1.59**	**(107,895)**	**589,665**	**1.34**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	KELSEY									
1135A	DAMS, DYKES AND WEIRS	2101	125-R4	(10)	9,296,418	97,650	1.05	7,713	105,363	1.13
1135B	POWERHOUSE	2101	125-R4	(10)	71,294,313	803,177	1.13	39,468	842,645	1.18
1135C	POWERHOUSE RENOVATIONS	2101	40-SQ	(10)						2.75 *
1135D	SPILLWAY	2101	80-R3	(10)	7,196,926	100,394	1.39	22,630	123,024	1.71
1135E	WATER CONTROL SYSTEMS	2101	65-R4	(10)	35,342,564	598,703	1.69	2,498	601,201	1.70
1135F	ROADS AND SITE IMPROVEMENTS	2101	50-R3	(10)	12,310,412	270,829	2.20	29,682	300,511	2.44
1135G	TURBINES AND GENERATORS	2101	60-S3	(10)	146,383,857	2,689,071	1.84	97,340	2,786,411	1.90
1135H	GOVERNORS AND EXCITATION SYSTEM	2101	50-R4	(10)	6,948,606	152,869	2.20	3,544	156,413	2.25
1135L	LICENCE RENEWAL	2101	50-SQ	0						2.00 *
1135P	A/C ELECTRICAL POWER SYSTEMS	2101	55-R4	(10)	40,494,515	810,700	2.00	45,444	856,144	2.11
1135Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2101	25-S2	(10)	13,650,816	597,501	4.38	40,274	637,775	4.67
1135R	AUXILIARY STATION PROCESSES	2101	50-R2	(10)	9,929,302	218,445	2.20	(1,247)	217,198	2.19
1135X	SUPPORT BUILDINGS	2101	65-S3	(10)	13,448,502	228,485	1.70	12,098	240,583	1.79
1135W	SUPPORT BUILDING RENOVATIONS	2101	20-SQ	(10)	1,598,817	87,935	5.50	(8,279)	79,656	4.98
	TOTAL KELSEY				**367,895,048**	**6,655,759**	**1.81**	**291,166**	**6,946,925**	**1.89**
	GRAND RAPIDS									
1140A	DAMS, DYKES AND WEIRS	2091	125-R4	(10)	56,613,946	600,907	1.06	(27,383)	573,524	1.01
1140B	POWERHOUSE	2091	125-R4	(10)	24,506,522	240,943	0.98	(15,347)	225,596	0.92
1140C	POWERHOUSE RENOVATIONS	2091	40-SQ	(10)	31,603	869	2.75	(63)	806	2.55
1140D	SPILLWAY	2091	80-R3	(10)	5,451,760	75,261	1.38	(5,678)	69,583	1.28
1140E	WATER CONTROL SYSTEMS	2091	65-R4	(10)	15,982,492	270,743	1.69	(94,728)	176,016	1.10
1140F	ROADS AND SITE IMPROVEMENTS	2091	50-R3	(10)	2,581,475	56,792	2.20	(14,821)	41,971	1.63
1140G	TURBINES AND GENERATORS	2091	60-S3	(10)	113,213,625	2,079,840	1.84	(14,360)	2,065,480	1.82
1140H	GOVERNORS AND EXCITATION SYSTEM	2091	50-R4	(10)	1,922,915	42,304	2.20	155	42,459	2.21 **
1140L	LICENCE RENEWAL	2091	50-SQ	0	83,122,204	1,662,444	2.00		1,662,444	2.00 **
1140P	A/C ELECTRICAL POWER SYSTEMS	2091	55-R4	(10)	8,240,545	164,976	2.00	(13,518)	151,458	1.84
1140Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2091	25-S2	(10)	4,690,245	206,371	4.40	(23,640)	182,731	3.90
1140R	AUXILIARY STATION PROCESSES	2091	50-R2	(10)	12,334,108	272,020	2.21	(22,872)	249,149	2.02
1140X	SUPPORT BUILDINGS	2091	65-S3	(10)	8,700,819	147,536	1.70	(419)	147,117	1.69 **
1140W	SUPPORT BUILDING RENOVATIONS	2091	20-SQ	(10)	6,828,234	375,553	5.50	11,679	387,232	5.67
1140Z	COMMUNITY DEVELOPMENT COSTS ***	2091	79-SQ	0	135,205,073	1,717,104	1.27	(86,566)	1,630,538	1.21
	TOTAL GRAND RAPIDS				**479,425,566**	**7,913,663**	**1.65**	**(307,561)**	**7,606,102**	**1.59**
	KETTLE									
1145A	DAMS, DYKES AND WEIRS	2111	125-R4	(10)	45,280,663	414,252	0.91	(24,547)	389,705	0.86
1145B	POWERHOUSE	2111	125-R4	(10)	146,313,138	1,342,153	0.92	(78,617)	1,263,536	0.86
1145C	POWERHOUSE RENOVATIONS	2111	40-SQ	(10)						2.75 *
1145D	SPILLWAY	2111	80-R3	(10)	25,406,960	349,346	1.38	(28,140)	321,206	1.26
1145E	WATER CONTROL SYSTEMS	2111	65-R4	(10)	19,033,816	322,433	1.69	(133,748)	188,685	0.99
1145F	ROADS AND SITE IMPROVEMENTS	2111	50-R3	(10)	556,723	12,248	2.20	23	12,271	2.20
1145G	TURBINES AND GENERATORS	2111	60-S3	(10)	99,163,384	1,821,631	1.84	60,979	1,882,610	1.90
1145H	GOVERNORS AND EXCITATION SYSTEM	2111	50-R4	(10)	6,930,643	152,474	2.20	(4,196)	148,278	2.14
1145L	LICENCE RENEWAL	2111	50-SQ	0						2.00 *
1145P	A/C ELECTRICAL POWER SYSTEMS	2111	55-R4	(10)	38,779,613	776,368	2.00	16,005	792,373	2.04
1145Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2111	25-S2	(10)	16,263,031	715,573	4.40	(32,101)	683,472	4.20
1145R	AUXILIARY STATION PROCESSES	2111	50-R2	(10)	19,306,615	424,746	2.20	(73,196)	351,550	1.82
1145X	SUPPORT BUILDINGS	2111	65-S3	(10)	2,456,258	41,609	1.69	1,281	42,890	1.75
1145W	SUPPORT BUILDING RENOVATIONS	2111	20-SQ	(10)						5.50
	TOTAL KETTLE				**419,490,845**	**6,372,833**	**1.52**	**(296,256)**	**6,076,577**	**1.45**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	LAURIE RIVER									
1150A	DAMS, DYKES AND WEIRS	2035	125-R4	(10)	355,538	8,455	2.38	2,919	11,374	3.20
1150B	POWERHOUSE	2035	125-R4	(10)	7,664,146	267,958	3.50	29,931	297,889	3.89
1150C	POWERHOUSE RENOVATIONS	2035	40-SQ	(10)						5.24 *
1150D	SPILLWAY	2035	80-R3	(10)	870,000	24,499	2.82	5,457	29,956	3.44
1150E	WATER CONTROL SYSTEMS	2035	65-R4	(10)	458,033	13,250	2.89	2,871	16,121	3.52
1150F	ROADS AND SITE IMPROVEMENTS	2035	50-R3	(10)	1,441,914	43,351	3.01	9,797	53,148	3.69
1150G	TURBINES AND GENERATORS	2035	60-S3	(10)	4,603,136	176,554	3.84	12,784	189,338	4.11
1150H	GOVERNORS AND EXCITATION SYSTEM	2035	50-R4	(10)	882,653	36,347	4.12	1,505	37,852	4.29
1150L	LICENCE RENEWAL	2035	50-SQ	0						4.76 *
1150P	A/C ELECTRICAL POWER SYSTEMS	2035	55-R4	(10)	1,441,945	44,310	3.07	7,967	52,277	3.63
1150Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2035	25-S2	(10)	1,220,047	54,203	4.44	22,434	76,637	6.28
1150R	AUXILIARY STATION PROCESSES	2035	50-R2	(10)	308,504	9,871	3.20	1,639	11,510	3.73
1150X	SUPPORT BUILDINGS	2035	65-S3	(10)	355,919	9,475	2.66	2,473	11,948	3.36
1150W	SUPPORT BUILDING RENOVATIONS	2035	20-SQ	(10)						5.50 *
	TOTAL LAURIE RIVER				**19,601,835**	**688,273**	**3.51**	**99,778**	**788,051**	**4.02**
	JENPEG									
1155A	DAMS, DYKES AND WEIRS	2118	125-R4	(10)	16,438,690	157,050	0.96	(7,488)	149,562	0.91
1155B	POWERHOUSE	2118	125-R4	(10)	76,905,294	704,619	0.92	(12,566)	692,053	0.90
1155C	POWERHOUSE RENOVATIONS	2118	40-SQ	(10)	26,446	727	2.75		727	2.75 **
1155D	SPILLWAY	2118	80-R3	(10)	14,942,733	205,467	1.38	(3,114)	202,353	1.35
1155E	WATER CONTROL SYSTEMS	2118	65-R4	(10)	17,167,202	290,812	1.69	(77,842)	212,970	1.24
1155F	ROADS AND SITE IMPROVEMENTS	2118	50-R3	(10)	1,563,205	34,391	2.20	(2,106)	32,286	2.07
1155G	TURBINES AND GENERATORS	2118	60-S3	(10)	91,716,371	1,684,830	1.84	51,840	1,736,670	1.89
1155H	GOVERNORS AND EXCITATION SYSTEM	2118	50-R4	(10)						2.20 *
1155L	LICENCE RENEWAL	2118	50-SQ	0						2.00 *
1155P	A/C ELECTRICAL POWER SYSTEMS	2118	55-R4	(10)	21,641,608	433,265	2.00	(42,032)	391,233	1.81
1155Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2118	25-S2	(10)	3,606,713	158,695	4.40	(9,031)	149,664	4.15
1155R	AUXILIARY STATION PROCESSES	2118	50-R2	(10)	13,685,752	301,087	2.20	(37,706)	263,381	1.92
1155X	SUPPORT BUILDINGS	2118	65-S3	(10)	7,885,397	133,579	1.69	(391)	133,188	1.69
1155W	SUPPORT BUILDING RENOVATIONS	2118	20-SQ	(10)						5.50 *
	TOTAL JENPEG				**265,579,412**	**4,104,522**	**1.55**	**(140,436)**	**3,964,086**	**1.49**
	LAKE WINNIPEG REGULATION									
1160A	DAMS, DYKES AND WEIRS		125-R4	(10)	110,416,014	971,661	0.88	(66,197)	905,464	0.82
1160L	LICENCE RENEWAL		50-SQ	0	250,000	5,000	2.00	41	5,041	2.02
1160Z	COMMUNITY DEVELOPMENT COSTS ***		85-SQ	0	436,787,857	5,154,097	1.18		5,154,097	1.18 **
	TOTAL LAKE WINNIPEG REGULATION				**547,453,871**	**6,130,758**	**1.12**	**(66,156)**	**6,064,602**	**1.11**
	CHURCHILL RIVER DIVERSION									
1165A	DAMS, DYKES AND WEIRS		125-R4	(10)	120,816,679	1,063,187	0.88	(900)	1,062,287	0.88
1165D	SPILLWAY		80-R3	(10)	59,622,870	819,814	1.37	10,135	829,949	1.39
1165E	WATER CONTROL SYSTEMS		65-R4	(10)	18,858,667	319,466	1.69	(99,018)	220,449	1.17
1165F	ROADS AND SITE IMPROVEMENTS		50-R3	(10)	7,284,036	160,249	2.20	(6,590)	153,659	2.11
1165L	LICENCE RENEWAL		50-SQ	0						2.00 *
1165P	A/C ELECTRICAL POWER SYSTEMS		55-R4	(10)	1,710,889	34,252	2.00	(2,107)	32,145	1.88
1165Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	(10)	1,541,737	67,836	4.40	5,856	73,692	4.78
1165R	AUXILIARY STATION PROCESSES		50-R2	(10)	1,864,257	41,014	2.20	(4,379)	36,635	1.97
1165X	SUPPORT BUILDINGS		65-S3	(10)	79,309	1,343	1.69	15	1,358	1.71
1165W	SUPPORT BUILDING RENOVATIONS		20-SQ	(10)						5.50
1165Z	COMMUNITY DEVELOPMENT COSTS ***		90-SQ	0	351,065,147	3,896,823	1.11	(150,766)	3,746,057	1.07
	TOTAL CHURCHILL RIVER DIVERSION				**562,843,590**	**6,403,984**	**1.14**	**(247,753)**	**6,156,231**	**1.09**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)	
	LONG SPRUCE										
1170A	DAMS, DYKES AND WEIRS	2118	125-R4	(10)	65,392,344	600,041	0.92	(8,880)	591,161	0.90	
1170B	POWERHOUSE	2118	125-R4	(10)	143,800,935	1,317,683	0.92	(19,930)	1,297,753	0.90	
1170C	POWERHOUSE RENOVATIONS	2118	40-SQ	(10)						2.75	*
1170D	SPILLWAY	2118	80-R3	(10)	42,273,617	581,262	1.37	(6,105)	575,157	1.36	
1170E	WATER CONTROL SYSTEMS	2118	65-R4	(10)	57,946,281	981,610	1.69	(409,281)	572,330	0.99	
1170F	ROADS AND SITE IMPROVEMENTS	2118	50-R3	(10)	1,376,630	30,286	2.20	(1,749)	28,537	2.07	
1170G	TURBINES AND GENERATORS	2118	60-S3	(10)	143,328,643	2,632,947	1.84	64,795	2,697,742	1.88	
1170H	GOVERNORS AND EXCITATION SYSTEM	2118	50-R4	(10)	145,844	3,209	2.20	(30)	3,179	2.18	
1170L	LICENCE RENEWAL	2118	50-SQ	0						2.00	*
1170P	A/C ELECTRICAL POWER SYSTEMS	2118	55-R4	(10)	30,610,740	612,827	2.00	(64,830)	547,997	1.79	
1170Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2118	25-S2	(10)	13,111,957	576,926	4.40	(4,296)	572,630	4.37	
1170R	AUXILIARY STATION PROCESSES	2118	50-R2	(10)	12,385,777	272,487	2.20	(73,696)	198,791	1.60	
1170X	SUPPORT BUILDINGS	2118	65-S3	(10)	160,484	2,719	1.69	(7)	2,712	1.69	
1170W	SUPPORT BUILDING RENOVATIONS	2118	20-SQ	(10)	205,681	11,312	5.50		11,312	5.50	**
	TOTAL LONG SPRUCE				**510,738,934**	**7,623,309**	**1.49**	**(524,008)**	**7,099,301**	**1.39**	
	LIMESTONE										
1175A	DAMS, DYKES AND WEIRS	2131	125-R4	(10)	33,287,049	303,962	0.91	(1,116)	302,846	0.91	
1175B	POWERHOUSE	2131	125-R4	(10)	461,590,745	4,216,707	0.91	(17,182)	4,199,526	0.91	
1175C	POWERHOUSE RENOVATIONS	2131	40-SQ	(10)						2.75	*
1175D	SPILLWAY	2131	80-R3	(10)	201,416,380	2,769,475	1.37	(6,134)	2,763,341	1.37	
1175E	WATER CONTROL SYSTEMS	2131	65-R4	(10)	116,325,934	1,970,561	1.69	(350,126)	1,620,435	1.39	
1175F	ROADS AND SITE IMPROVEMENTS	2131	50-R3	(10)	17,384,603	382,461	2.20	(10,489)	371,972	2.14	
1175G	TURBINES AND GENERATORS	2131	60-S3	(10)	404,329,629	7,427,535	1.84	249,274	7,676,809	1.90	
1175H	GOVERNORS AND EXCITATION SYSTEM	2131	50-R4	(10)	16,598,509	365,167	2.20	(7,502)	357,665	2.15	
1175L	LICENCE RENEWAL	2131	50-SQ	0						2.00	*
1175P	A/C ELECTRICAL POWER SYSTEMS	2131	55-R4	(10)	144,588,941	2,894,671	2.00	(158,573)	2,736,098	1.89	
1175Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2131	25-S2	(10)	8,782,898	386,447	4.40	(20,828)	365,619	4.16	
1175R	AUXILIARY STATION PROCESSES	2131	50-R2	(10)	36,388,654	800,550	2.20	(154,607)	645,943	1.78	
1175X	SUPPORT BUILDINGS	2131	65-S3	(10)	5,707,366	96,683	1.69	661	97,344	1.71	
1175W	SUPPORT BUILDING RENOVATIONS	2131	20-SQ	(10)	652,644	35,895	5.50		35,895	5.50	**
	TOTAL LIMESTONE				**1,447,053,352**	**21,650,114**	**1.50**	**(476,622)**	**21,173,492**	**1.46**	
	WUSKWATIM										
1180A	DAMS, DYKES AND WEIRS	2152	125-R4	(10)	4,694,366	42,860	0.91	(214)	42,646	0.91	
1180B	POWERHOUSE	2152	125-R4	(10)	18,227,672	166,419	0.91	(683)	165,736	0.91	
1180C	POWERHOUSE RENOVATIONS	2152	40-SQ	(10)						2.75	*
1180D	SPILLWAY	2152	80-R3	(10)	2,875,828	39,543	1.38	(304)	39,239	1.36	
1180E	WATER CONTROL SYSTEMS	2152	65-R4	(10)	3,087,285	52,299	1.69	(571)	51,728	1.68	
1180F	ROADS AND SITE IMPROVEMENTS	2152	50-R3	(10)	2,495,203	54,894	2.20	(158)	54,736	2.19	
1180G	TURBINES AND GENERATORS	2152	60-S3	(10)	4,652,074	85,459	1.84	(542)	84,918	1.83	
1180H	GOVERNORS AND EXCITATION SYSTEM	2152	50-R4	(10)	169,166	3,722	2.20	(15)	3,707	2.19	
1180P	A/C ELECTRICAL POWER SYSTEMS	2152	55-R4	(10)	1,691,663	33,867	2.00	(160)	33,707	1.99	
1180Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2152	25-S2	(10)	1,141,873	50,242	4.40	(1,784)	48,458	4.24	
1180R	AUXILIARY STATION PROCESSES	2152	50-R2	(10)	2,029,996	44,660	2.20	(1,332)	43,328	2.13	
1180X	SUPPORT BUILDINGS	2152	65-S3	(10)	930,415	15,761	1.69	(52)	15,709	1.69	
1180W	SUPPORT BUILDING RENOVATIONS	2152	20-SQ	(10)						5.50	**
	TOTAL WUSKWATIM				**41,995,540**	**589,726**	**1.40**	**(5,816)**	**583,911**	**1.39**	
	INFRASTRUCTURE SUPPORTING GENERATION										
1199F	PROVINCIAL ROADS		50-R3	(10)	25,412,921	559,084	2.20	73,165	632,249	2.49	
1199V	TOWN SITE BUILDINGS		55-R4	(7)	82,260,635	1,601,944	1.95	139,151	1,741,095	2.12	
1199W	TOWN SITE BUILDING RENOVATIONS		20-SQ	(6)	27,027,620	1,432,464	5.30		1,432,464	5.30	**
1199Y	TOWN SITE OTHER INFRASTRUCTURE		45-R4	(10)	29,155,301	711,972	2.44	195,037	907,009	3.11	
	TOTAL INFRASTRUCTURE SUPPORTING GENERATION				**163,856,477**	**4,305,464**	**2.63**	**407,353**	**4,712,817**	**2.88**	
	TOTAL HYDRAULIC GENERATION				**5,445,593,386**	**90,409,020**	**1.66**	**(703,166)**	**89,705,854**	**1.65**	

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK (1)	LIFE SPAN DATE	SURVIVOR CURVE (2)	NET SALVAGE (3)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (4)	CALCULATED ANNUAL ACCRUAL AMOUNT (5)	CALCULATED ANNUAL ACCRUAL RATE (%) (6)=(5)/(4)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RELATED TO LIFE RATE (%) (9)=(8)/(4)
	THERMAL GENERATION									
	BRANDON UNIT 5 (COAL)									
1205B	POWERHOUSE	2020	75-R5	0	11,729,518	438,783	3.74	91,366	530,149	4.52
1205C	POWERHOUSE RENOVATIONS	2020	40-SQ	0	396,538	58,727	14.81	4,236	62,963	15.88
1205F	ROADS AND SITE IMPROVEMENTS	2020	50-R3	0	4,018,549	181,309	4.51	34,292	215,601	5.37
1205G	TURBINES AND GENERATORS	2020	60-S3	0	19,611,168	984,510	5.02	139,027	1,123,537	5.73
1205H	GOVERNORS AND EXCITATION SYSTEM	2020	50-R4	0	2,343,861	118,834	5.07	10,214	129,048	5.51
1205J	STEAM GENERATOR AND AUXILIARIES	2020	60-S2.5	0	14,655,599	567,116	3.87	28,135	595,251	4.06 **
1205L	LICENCE RENEWAL	2020	50-SQ	0	2,198,654	325,621	14.81		325,621	14.81 **
1205P	A/C ELECTRICAL POWER SYSTEMS	2020	55-R4	0	8,026,175	311,077	3.88	62,420	373,497	4.65
1205Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2020	25-S2	0	25,758,061	1,215,485	4.72	(71,227)	1,144,258	4.44
1205R	AUXILIARY STATION PROCESSES	2020	50-R2	0	47,355,066	2,150,146	4.54	385,726	2,535,872	5.36
1205X	SUPPORT BUILDINGS	2020	65-S3	0	7,837,127	391,458	4.99	76,591	468,049	5.97
1205W	SUPPORT BUILDING RENOVATIONS	2020	20-SQ	0						16.67 *
	TOTAL BRANDON UNIT 5 (COAL)				**143,930,317**	**6,743,066**	**4.68**	**760,780**	**7,503,846**	**5.21**
	BRANDON UNITS 6 AND 7									
1210B	POWERHOUSE		75-R5	(10)	14,925,029	218,353	1.46	(12,744)	205,609	1.38
1210C	POWERHOUSE RENOVATIONS		40-SQ	(10)	144,571	3,976	2.75	(45)	3,931	2.72
1210G	TURBINES AND GENERATORS		60-S3	(10)	11,222,428	206,156	1.84	(15,922)	190,234	1.70
1210H	GOVERNORS AND EXCITATION SYSTEM		50-R4	(10)						2.20 *
1210K	COMBUSTION TURBINE		25-R3	(10)	143,303,747	6,305,365	4.40	(758,068)	5,547,297	3.87
1210L	LICENCE RENEWAL		50-SQ	0						2.00 *
1210M	COMBUSTION TURBINE OVERHAULS		15-SQ	(10)						7.33 *
1210P	A/C ELECTRICAL POWER SYSTEMS		55-R4	(10)	6,346,535	127,058	2.00	(7,790)	119,268	1.88
1210Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	(10)	1,295,814	57,016	4.40	1,583	58,599	4.52
1210R	AUXILIARY STATION PROCESSES		50-R2	(10)	10,639,560	234,070	2.20	(30,761)	203,309	1.91
	TOTAL BRANDON UNITS 6 AND 7				**187,877,685**	**7,151,994**	**3.81**	**(823,747)**	**6,328,247**	**3.37**
	SELKIRK									
1215B	POWERHOUSE		75-R5	0	6,808,812	90,557	1.33	(39,049)	51,508	0.76
1215C	POWERHOUSE RENOVATIONS		40-SQ	0	451,038	11,276	2.50	(236)	11,040	2.45
1215F	ROADS AND SITE IMPROVEMENTS		50-R3	0	1,630,443	32,609	2.00	(10,798)	21,812	1.34
1215G	TURBINES AND GENERATORS		60-S3	0	22,750,003	379,925	1.67	(131,987)	247,938	1.09
1215H	GOVERNORS AND EXCITATION SYSTEM		50-R4	0	17,307	346	2.00	(150)	196	1.13
1215J	STEAM GENERATOR AND AUXILIARIES		60-S2.5	0	51,721,352	863,747	1.67	(90,587)	773,160	1.49
1215L	LICENCE RENEWAL		50-SQ	0						2.00 *
1215P	A/C ELECTRICAL POWER SYSTEMS		55-R4	0	3,171,700	57,725	1.82	(24,117)	33,608	1.06
1215Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	0	5,286,066	208,225	3.94	(96,641)	111,584	2.11
1215R	AUXILIARY STATION PROCESSES		50-R2	0	14,897,376	297,948	2.00	(121,123)	176,825	1.19
1215X	SUPPORT BUILDINGS		65-S3	0	1,033,229	15,912	1.54	(4,928)	10,984	1.06
1215W	SUPPORT BUILDING RENOVATIONS		20-SQ	0						5.00 *
	TOTAL SELKIRK				**107,767,327**	**1,958,270**	**1.82**	**(519,616)**	**1,438,654**	**1.33**
	TOTAL THERMAL GENERATION				**439,575,329**	**15,853,330**	**3.61**	**(582,584)**	**15,270,747**	**3.47**
	TOTAL GENERATION				**5,885,168,715**	**106,262,350**	**1.81**	**(1,285,750)**	**104,976,600**	**1.78**
	DIESEL GENERATION									
1300B	BUILDINGS		25-R3	(5)	8,263,526	347,068	4.20	(86,740)	260,328	3.15
1300C	BUILDING RENOVATIONS		15-SQ	0	17,929	1,196	6.67		1,196	6.67
1300M	ENGINES AND GENERATORS - OVERHAULS		4-SQ	0	1,998,461	499,615	25.00		499,615	25.00 **
1300N	ENGINES AND GENERATORS		22-R2	0	16,774,955	763,260	4.55	(387,383)	375,877	2.24
1300Q	ACCESSORY STATION EQUIPMENT		20-R3	(5)	15,892,750	834,369	5.25	(246,306)	588,063	3.70
1300T	FUEL STORAGE AND HANDLING		25-R2	(5)	5,083,046	213,488	4.20	(92,959)	120,529	2.37
	TOTAL DIESEL GENERATION				**48,030,666**	**2,658,996**	**5.54**	**(813,388)**	**1,845,608**	**3.84**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)	
	TRANSMISSION										
2000F	ROADS, TRAILS AND BRIDGES		50-S2.5	(10)	10,686,118	235,095	2.20	(836)	234,259	2.19	
2000G	METAL TOWERS AND CONCRETE POLES		85-R4	(25)	481,955,524	7,108,844	1.48	307,537	7,416,381	1.54	
2000J	POLES AND FIXTURES		55-R3	(35)	117,066,069	2,876,313	2.46	29,101	2,905,414	2.48	**
2000K	GROUND LINE TREATMENT		10-SQ	0	2,297,990	229,799	10.00		229,799	10.00	**
2000L	OVERHEAD CONDUCTOR AND DEVICES		80-R4	(15)	349,810,506	5,028,526	1.44	(588,741)	4,439,785	1.27	
2000M	UNDERGROUND CABLE AND DEVICES		45-R3	(5)	960,535	22,390	2.33	(3,551)	18,839	1.96	
2000Z	COMMUNITY DEVELOPMENT COSTS ***		79-SQ	0	17,625,510	223,844	1.27	(692)	223,152	1.27	
	TOTAL TRANSMISSION				**980,402,254**	**15,724,811**	**1.60**	**(257,181)**	**15,467,630**	**1.58**	
	SUBSTATIONS										
3000B	BUILDINGS		65-R4	(5)	167,465,733	2,707,921	1.62	(242,630)	2,465,291	1.47	**
3000C	BUILDING RENOVATIONS		20-SQ	0	16,023,446	800,762	5.00		800,762	5.00	**
3000F	ROADS, STEEL STRUCTURES AND CIVIL SITE WORKS		50-R4	(10)	301,966,571	6,642,922	2.20	(745,588)	5,897,335	1.95	
3000J	POLES AND FIXTURES		45-R2.5	(35)	8,976,505	269,026	3.00	1,311	270,337	3.01	
3100R	POWER TRANSFORMERS		50-R1.5	(15)	346,530,004	7,970,190	2.30	475,001	8,445,191	2.44	
3100S	OTHER TRANSFORMERS		50-S1	(15)	112,490,470	2,587,281	2.30	(14,701)	2,572,580	2.29	
3100T	INTERRUPTING EQUIPMENT		50-R2.5	(15)	210,045,708	4,831,051	2.30	471,646	5,302,697	2.52	
3100U	OTHER STATION EQUIPMENT		45-R3	(15)	553,640,228	14,112,219	2.55	(422,813)	13,689,406	2.47	
3100V	ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	(10)	222,763,291	9,785,631	4.39	(1,292,758)	8,492,873	3.81	
3200M	SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS		65-R4	(15)	122,026,806	2,161,095	1.77	32,418	2,193,513	1.80	
3200N	SYNCHRONOUS CONDENSER OVERHAULS		15-SQ	(15)	47,815,173	3,420,109	7.15		3,420,109	7.15	**
3200P	HVDC CONVERTER EQUIPMENT		30-S4	(15)	434,607,924	16,643,310	3.83	(2,643,466)	13,999,844	3.22	
3200S	HVDC SERIALIZED EQUIPMENT		30-R5	(15)	213,665,609	7,781,788	3.64	(1,296,214)	6,485,574	3.04	
3200U	HVDC ACCESSORY STATION EQUIPMENT		36-R3	(15)	169,254,248	5,411,058	3.20	(366,323)	5,044,735	2.98	
3200V	HVDC ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	(10)	47,913,305	2,108,185	4.40	(621,988)	1,486,197	3.10	
	TOTAL SUBSTATIONS				**2,975,185,020**	**87,232,548**	**2.93**	**(6,666,104)**	**80,566,444**	**2.71**	
	DISTRIBUTION										
4000A	CONCRETE DUCTLINE AND MANHOLES		75-R4	(5)	70,181,420	1,581,993	2.25	(18,117)	1,563,876	2.23	
4000C	CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT		30-R4	(5)	7,368,727	257,648	3.50	11,788	269,436	3.66	
4000G	METAL TOWERS		60-R3	(25)	10,853,698	226,571	2.09	1,503	228,074	2.10	
4000J	POLES AND FIXTURES		65-S0.5	(38)	668,956,088	14,216,655	2.13	(1,138,184)	13,078,471	1.96	
4000K	GROUND LINE TREATMENT		12-SQ	0	34,478,470	2,872,057	8.33	(324,784)	2,547,273	7.39	
4000L	OVERHEAD CONDUCTOR AND DEVICES		60-R1.5	(38)	717,203,040	16,528,661	2.30	(455,108)	16,073,553	2.24	
4000M	UNDERGROUND CABLE AND DEVICES - 66 KV		60-S1	(5)	27,891,495	489,077	1.75	(8,358)	480,720	1.72	
4000N	UNDERGROUND CABLE AND DEVICES - PRIMARY		60-R3	(5)	374,567,850	6,568,047	1.75	(210,888)	6,357,159	1.70	
4000P	UNDERGROUND CABLE AND DEVICES - SECONDARY		44-S3	(5)	249,788,828	5,953,717	2.38	(283,113)	5,670,604	2.27	
4000Q	SERIALIZED EQUIPMENT - OVERHEAD		45-R3	(15)	218,784,786	5,585,264	2.55	(604,758)	4,980,506	2.28	
4000R	DSC - HIGH VOLTAGE TRANSFORMERS		50-R3	(15)	25,320,598	582,374	2.30	10,594	592,968	2.34	
4000S	SERIALIZED EQUIPMENT - UNDERGROUND		42-R3	(15)	213,763,677	5,850,712	2.74	(282,292)	5,568,420	2.60	
4000V	ELECTRONIC EQUIPMENT		10-SQ	0	739,972	73,997	10.00	3,902	77,899	10.53	
4000W	SERVICES		35-R1.5	(40)	73,127,688	2,928,033	4.00	(792,562)	2,135,471	2.92	
4000X	STREET LIGHTING		45-R3	(15)	182,346,807	4,653,076	2.55	12,572	4,665,648	2.56	
	TOTAL DISTRIBUTION				**2,875,373,143**	**68,367,882**	**2.38**	**(4,077,807)**	**64,290,076**	**2.24**	
	METERS										
4900V	METERS - ELECTRONIC		15-L3	0	18,913,638	1,261,540	6.67	556,699	1,818,239	9.61	
4900Y	METERS - ANALOG		26-L1.5	0	19,622,056	755,449	3.85	(1,931)	753,518	3.84	
4900W	METERING EXCHANGES		15-SQ	0	33,545,519	2,237,486	6.67		2,237,486	6.67	
4900Z	METERING TRANSFORMERS		50-R2.5	0	11,244,938	224,899	2.00	(22,725)	202,175	1.80	
	TOTAL METERS				**83,326,152**	**4,479,374**	**5.38**	**532,043**	**5,011,417**	**6.01**	

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)	
	COMMUNICATION										
5000B	BUILDINGS		65-R3	(5)	6,955,504	112,471	1.62	(14,481)	97,990	1.41	
5000C	BUILDING RENOVATIONS		20-SQ	(5)	3,486,352	182,798	5.24	(10,056)	172,742	4.95	
5000D	BUILDING - SYSTEM CONTROL CENTRE		75-R4	(5)	15,857,686	221,453	1.40	(1,669)	219,784	1.39	
5000G	COMMUNICATION TOWERS		60-R2	(5)	12,362,119	216,770	1.75	8,621	225,391	1.82	
5000H	FIBRE OPTIC AND METALLIC CABLE		35-R2.5	(4)	131,559,381	3,913,102	2.97	194,050	4,107,152	3.12	
5000J	CARRIER EQUIPMENT		20-R2.5	(5)	125,921,733	6,610,558	5.25	(640,797)	5,969,761	4.74	**
5000K	OPERATIONAL IT EQUIPMENT		5-SQ	(5)	4,821,768	1,012,571	21.00		1,012,571	21.00	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING		8-SQ	(5)	8,862,073	1,163,147	13.12	481,237	1,644,384	18.56	
5000N	OPERATIONAL DATA NETWORK		8-SQ	(5)	18,817,356	2,469,778	13.13		2,469,778	13.13	**
5000R	POWER SYSTEM CONTROL		15-S1.5	(5)	14,264,753	963,308	6.75	(160,879)	802,429	5.63	
	TOTAL COMMUNICATION				**342,908,725**	**16,865,956**	**4.92**	**(143,973)**	**16,721,983**	**4.88**	
	MOTOR VEHICLES										
6000E	PASSENGER VEHICLES		11-S2	20	1,145,330	83,288	7.27	(2,814)	80,474	7.03	
6000F	LIGHT TRUCKS		12-L4	10	69,461,644	5,207,539	7.50	(234,045)	4,973,494	7.16	
6000G	HEAVY TRUCKS		19-L4	7	73,416,587	3,591,393	4.89	(157,873)	3,433,520	4.68	
6000H	CONSTRUCTION EQUIPMENT		23-R2.5	20	21,130,532	735,343	3.48	(149,870)	585,473	2.77	
6000I	LARGE SOFT-TRACK EQUIPMENT		27-L1.5	15	15,620,474	491,264	3.15	(29,328)	461,936	2.96	
6000J	TRAILERS		35-S1	15	18,887,911	459,161	2.43	(9,004)	450,157	2.38	
6000K	MISCELLANEOUS VEHICLES		13-L1	15	6,114,461	399,672	6.54	(100,356)	299,317	4.90	
	TOTAL MOTOR VEHICLES				**205,776,939**	**10,967,660**	**5.33**	**(683,288)**	**10,284,372**	**5.00**	
	BUILDINGS										
8000B	BUILDINGS - GENERAL		65-R3	(5)	103,251,540	1,669,577	1.62	33,775	1,703,352	1.65	**
8000C	BUILDING RENOVATIONS		20-SQ	(5)	37,401,024	1,963,554	5.25	128,733	2,092,287	5.59	
8000D	BUILDING - 360 PORTAGE - CIVIL		100-R4	0	202,792,903	2,027,929	1.00	1,375	2,029,304	1.00	
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL		45-R3	0	77,339,398	1,716,935	2.22	5,514	1,722,449	2.23	**
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE		10-SQ	0	1,007,453	100,745	10.00		100,745	10.00	**
	TOTAL BUILDINGS				**421,792,317**	**7,478,740**	**1.77**	**169,397**	**7,648,137**	**1.81**	
	GENERAL EQUIPMENT										
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT		15-SQ	0	87,537,592	5,676,211	6.48		5,676,211	6.48	**
9000K	COMPUTER EQUIPMENT		5-SQ	0	49,555,418	9,911,084	20.00		9,911,084	20.00	**
9000L	OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	26,318,137	1,315,907	5.00		1,315,907	5.00	**
9000M	HOT WATER TANKS		6-SQ	0	881,848	147,004	16.67		147,004	16.67	**
	TOTAL GENERAL EQUIPMENT				**164,292,994**	**17,050,206**	**10.38**		**17,050,206**	**10.38**	
	EASEMENTS										**
A100A	EASEMENTS		75-SQ	0	66,021,103	878,081	1.33		878,081	1.33	**
	TOTAL EASEMENTS				**66,021,103**	**878,081**	**1.33**		**878,081**	**1.33**	
	COMPUTER SOFTWARE AND DEVELOPMENT										
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS		11-S6	0	111,692,382	10,152,838	9.09	(375,315)	9,777,523	8.75	
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS		10-SQ	0	48,787,249	4,878,725	10.00	(426,046)	4,452,679	9.13	
A200J	COMPUTER SOFTWARE - GENERAL		5-SQ	0	6,701,454	1,340,291	20.00		1,340,291	20.00	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL		5-SQ	0	4,652,481	930,496	20.00	339,877	1,270,373	27.31	
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA		7-S3	0	10,313,958	1,473,865	14.29	(642,555)	831,310	8.06	
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT				**182,147,524**	**18,776,215**	**10.31**	**(1,104,039)**	**17,672,176**	**9.70**	
	TOTAL MANITOBA HYDRO				**14,230,425,552**	**356,742,819**	**2.51**	**(14,330,090)**	**342,412,729**	**2.41**	

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK (1)	LIFE SPAN DATE	SURVIVOR CURVE (2)	NET SALVAGE (3)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (4)	CALCULATED ANNUAL ACCRUAL AMOUNT (5)	CALCULATED ANNUAL ACCRUAL RATE (%) (6)=(5)/(4)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RELATED TO LIFE RATE (%) (9)=(8)/(4)
	WUSKWATIM POWER LIMITED PARTNERSHIP ("WPLP")									
	PROPERTY, PLANT AND EQUIPMENT									
	HYDRAULIC GENERATION									
1181A	WPLP - DAMS, DYKES AND WEIRS	2152	125-R4	(10)	148,498,470	1,355,791	0.91	(676)	1,355,115	0.91
1181B	WPLP - POWERHOUSE	2152	125-R4	(10)	569,576,645	5,200,235	0.91	(2,687)	5,197,548	0.91
1181C	WPLP - POWERHOUSE RENOVATIONS	2152	40-SQ	(10)						2.75 *
1181D	WPLP - SPILLWAY	2152	80-R3	(10)	90,639,257	1,246,290	1.38	(3,785)	1,242,505	1.37
1181E	WPLP - WATER CONTROL SYSTEMS	2152	65-R4	(10)	98,584,694	1,670,025	1.69	(15,452)	1,654,573	1.68
1181F	WPLP - ROADS AND SITE IMPROVEMENTS	2152	50-R3	(10)	79,988,348	1,759,744	2.20	(4,425)	1,755,319	2.19
1181G	WPLP - TURBINES AND GENERATORS	2152	60-S3	(10)	149,857,582	2,752,884	1.84	1,471	2,754,355	1.84
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM	2152	50-R4	(10)	5,167,019	113,674	2.20	(251)	113,423	2.20
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS	2152	55-R4	(10)	49,908,667	999,172	2.00	(6,667)	992,505	1.99
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2152	25-S2	(10)	37,311,999	1,641,728	4.40	(14,952)	1,626,776	4.36
1181R	WPLP - AUXILIARY STATION PROCESSES	2152	50-R2	(10)	66,497,960	1,462,955	2.20	(18,364)	1,444,591	2.17
1181X	WPLP - SUPPORT BUILDINGS	2152	65-S3	(10)	29,258,457	495,638	1.69	(811)	494,827	1.69
1181W	WPLP - SUPPORT BUILDING RENOVATIONS	2152	20-SQ	(10)						5.50 *
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND	2152	95-SQ	0	389,662	4,091	1.05	(300)	3,791	0.97
	TOTAL GENERATION				**1,325,678,762**	**18,702,227**	**1.41**	**(66,897)**	**18,635,330**	**1.41**
	SUBSTATIONS									
3081B	WPLP - BUILDINGS		65-R4	(5)	326,268	5,276	1.62	1	5,277	1.62
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK		50-R4	(10)	1,761,913	38,762	2.20	(30)	38,732	2.20
3181R	WPLP - POWER TRANSFORMERS		50-R1.5	(15)	4,482,057	103,087	2.30	(750)	102,337	2.28
3181T	WPLP - INTERRUPTING EQUIPMENT		50-R2.5	(15)	839,984	19,320	2.30	(110)	19,210	2.29
3181U	WPLP - OTHER STATION EQUIPMENT		45-R3	(15)	1,621,291	41,392	2.55	(124)	41,268	2.55
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	(10)	1,065,222	46,870	4.40	(779)	46,091	4.33
	TOTAL SUBSTATIONS				**10,096,734**	**254,707**	**2.52**	**(1,792)**	**252,916**	**2.50**
	COMMUNICATION									
5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE		35-R2.5	(4)	150,000	4,462	2.97	(33)	4,429	2.95
5081J	WPLP - CARRIER EQUIPMENT		20-R2.5	(5)	50,000	2,625	5.25	(134)	2,492	4.98
	TOTAL COMMUNICATION				**200,000**	**7,087**	**3.54**	**(166)**	**6,921**	**3.46**
	MOTOR VEHICLES									
6081G	WPLP - HEAVY TRUCKS		19-L4	7	46,325	2,266	4.89	(1,141)	1,125	2.43
6081H	WPLP - CONSTRUCTION EQUIPMENT		23-R2.5	20	42,012	1,462	3.48	53	1,515	3.61
6081J	WPLP - TRAILERS		35-S1	15	82,208	1,998	2.43	12	2,010	2.45
6081K	WPLP - MISCELLANEOUS VEHICLES		13-L1	15	54,399	3,556	6.54	(85)	3,471	6.38
	TOTAL MOTOR VEHICLES				**224,944**	**9,282**	**4.13**	**(1,161)**	**8,121**	**3.61**
	GENERAL EQUIPMENT									
9081K	WPLP - COMPUTER EQUIPMENT		5-SQ	0	21,228	4,246	20.00	(921)	3,325	15.66
	TOTAL GENERAL EQUIPMENT				**21,228**	**4,246**	**20.00**	**(921)**	**3,325**	**15.66**
	TOTAL WPLP PROPERTY, PLANT AND EQUIPMENT				**1,336,221,667**	**18,977,549**	**1.42**	**(70,937)**	**18,906,612**	**1.41**
	INTANGIBLE ASSETS									
	TRANSMISSION									
2080F	WPLP - ROADS, TRAILS AND BRIDGES		50-S2.5	(10)	1,439,812	31,676	2.20	(220)	31,456	2.18
2080G	WPLP - METAL TOWERS AND CONCRETE POLES		85-R4	(25)	106,632,518	1,572,830	1.48	(3,119)	1,569,711	1.47
2080J	WPLP - POLES AND FIXTURES		55-R3	(35)	430,084	10,567	2.46	(26)	10,541	2.45
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES		80-R4	(15)	29,011,058	417,034	1.44	(1,687)	415,347	1.43
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND		79-SQ	0	1,909,456	24,250	1.27	(109)	24,141	1.26
	TOTAL TRANSMISSION				**139,422,928**	**2,056,357**	**1.47**	**(5,161)**	**2,051,196**	**1.47**

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	SUBSTATIONS									
3080B	WPLP - BUILDINGS		65-R4	(5)	11,080,091	179,165	1.62	38	179,203	1.62
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK		50-R4	(10)	44,652,522	982,355	2.20	(800)	981,555	2.20
3180R	WPLP - POWER TRANSFORMERS		50-R1.5	(15)	4,272,536	98,268	2.30	(650)	97,618	2.28
3180S	WPLP - OTHER TRANSFORMERS		50-S1	(15)	31,309,273	720,113	2.30	(9,932)	710,181	2.27
3180T	WPLP - INTERRUPTING EQUIPMENT		50-R2.5	(15)	25,624,773	589,370	2.30	(3,309)	586,061	2.29
3180U	WPLP - OTHER STATION EQUIPMENT		45-R3	(15)	19,617,296	500,830	2.55	(1,510)	499,320	2.55
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	(10)	19,286,904	848,624	4.40	(14,054)	834,570	4.33
	TOTAL SUBSTATIONS				**155,843,395**	**3,918,725**	**2.51**	**(30,217)**	**3,888,508**	**2.50**
	DISTRIBUTION									
4080J	WPLP - POLES AND FIXTURES		65-S0.5	(38)	187,208	3,979	2.13	(11)	3,968	2.12
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES		60-R1.5	(38)	315,541	7,272	2.30	(18)	7,254	2.30
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY		60-R3	(5)	819,462	14,369	1.75	(18)	14,351	1.75
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND		42-R3	(15)	29,630	811	2.74	(1)	810	2.73
	TOTAL DISTRIBUTION				**1,351,840**	**26,431**	**1.96**	**(48)**	**26,383**	**1.95**
	COMMUNICATION									
5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE		35-R2.5	(4)	4,463,440	132,761	2.97	(994)	131,767	2.95
5080J	WPLP - CARRIER EQUIPMENT		20-R2.5	(5)	2,508,284	131,685	5.25	(6,760)	124,925	4.98
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING		8-SQ	(5)	212,713	27,919	13.13	1,047	28,966	13.62
5080N	WPLP - OPERATIONAL DATA NETWORK		8-SQ	(5)	440,117	57,765	13.12	(2,044)	55,721	12.66
	TOTAL COMMUNICATION				**7,624,554**	**350,130**	**4.59**	**(8,752)**	**341,378**	**4.48**
	EASEMENTS									
A180A	WPLP - EASEMENTS		75-SQ	0	796,640	10,595	1.33		10,595	1.33 **
	TOTAL EASEMENTS				**796,640**	**10,595**	**1.33**		**10,595**	**1.33**
	TOTAL WPLP INTANGIBLE ASSETS				**305,039,358**	**6,362,238**	**2.09**	**(44,178)**	**6,318,060**	**2.07**
	TOTAL WUSKWATIM POWER LIMITED PARTNERSHIP				**1,641,261,025**	**25,339,787**		**(115,114)**	**25,224,673**	**1.54**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	GENERATION							
	HYDRAULIC GENERATION							
	GREAT FALLS							
1105A	DAMS, DYKES AND WEIRS	17,345,473	7,749,311	8,400,996	(651,685)	(8.41)	46.9	(13,895)
1105B	POWERHOUSE	7,990,993	3,724,335	4,120,534	(396,199)	(10.64)	46.1	(8,594)
1105C	POWERHOUSE RENOVATIONS	47,039	1,940	3,450	(1,510)	(77.81)	38.5	(39)
1105D	SPILLWAY	9,676,327	4,198,651	4,538,669	(340,018)	(8.10)	42.0	(8,096)
1105E	WATER CONTROL SYSTEMS	24,245,253	8,781,841	12,000,543	(3,218,702)	(36.65)	41.3	(77,935)
1105F	ROADS AND SITE IMPROVEMENTS	935,986	82,042	81,796	246	0.30	41.8	6
1105G	TURBINES AND GENERATORS	33,818,312	8,938,980	7,031,203	1,907,777	21.34	35.4	53,892
1105H	GOVERNORS AND EXCITATION SYSTEM	1,154,724	262,936	282,594	(19,658)	(7.48)	40.1	(490)
1105L	LICENCE RENEWAL							*
1105P	A/C ELECTRICAL POWER SYSTEMS	9,493,088	3,886,455	4,425,761	(539,306)	(13.88)	35.4	(15,235)
1105Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	19,506,209	8,812,787	10,107,853	(1,295,066)	(14.70)	15.3	(84,645)
1105R	AUXILIARY STATION PROCESSES	10,221,178	3,002,033	4,161,341	(1,159,308)	(38.62)	35.4	(32,749)
1105X	SUPPORT BUILDINGS	1,495,253	753,445	844,526	(91,081)	(12.09)	41.6	(2,189)
1105W	SUPPORT BUILDING RENOVATIONS	18,859	2,593	2,420	173	6.66	17.5	**
	TOTAL GREAT FALLS	**135,948,694**	**50,197,349**	**56,001,684**	**(5,804,335)**	**(11.56)**		**(189,969)**
	POINTE DU BOIS							
1110A	DAMS, DYKES AND WEIRS	20,718,888	3,257,888	6,598,928	(3,341,040)	(102.55)	25.2	(132,581)
1110B	POWERHOUSE	6,054,784	1,274,172	2,161,160	(886,988)	(69.61)	25.2	(35,198)
1110C	POWERHOUSE RENOVATIONS	1,897,782	84,262	119,782	(35,520)	(42.15)	25.3	(1,404)
1110D	SPILLWAY - ORIGINAL	7,797,851	4,557,249	2,809,584	1,747,665	38.35	1.0	1,747,665
1110E	WATER CONTROL SYSTEMS	4,466,812	1,244,373	2,540,169	(1,295,796)	(104.13)	25.1	(51,625)
1110F	ROADS AND SITE IMPROVEMENTS	1,055,707	91,064	94,281	(3,217)	(3.53)	24.7	(130)
1110G	TURBINES AND GENERATORS	31,899,060	6,422,054	12,317,530	(5,895,476)	(91.80)	25.1	(234,880)
1110H	GOVERNORS AND EXCITATION SYSTEM							*
1110L	LICENCE RENEWAL							*
1110P	A/C ELECTRICAL POWER SYSTEMS	7,759,986	1,278,313	2,390,470	(1,112,157)	(87.00)	25.1	(44,309)
1110Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,037,485	156,640	252,040	(95,400)	(60.90)	20.2	(4,723)
1110R	AUXILIARY STATION PROCESSES	5,357,425	813,874	1,169,630	(355,756)	(43.71)	23.9	(14,885)
1110X	SUPPORT BUILDINGS	882,202	193,074	307,773	(114,699)	(59.41)	25.2	(4,552)
1110W	SUPPORT BUILDING RENOVATIONS	347,164	86,476	143,680	(57,204)	(66.15)	16.0	(3,575)
	TOTAL POINTE DU BOIS	**89,275,145**	**19,459,439**	**30,905,028**	**(11,445,589)**	**(58.82)**		**1,219,803**
	POINTE DU BOIS - NEW							
1111A	DAMS, DYKES AND WEIRS							*
1111D	SPILLWAY							*
1111E	WATER CONTROL SYSTEMS							*
1111F	ROADS AND SITE IMPROVEMENTS							*
1111P	A/C ELECTRICAL POWER SYSTEMS							*
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS							*
1111R	AUXILIARY STATION PROCESSES							*
1111X	SUPPORT BUILDINGS							*
1111W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL POINTE DU BOIS - NEW	**0**	**0**	**0**	**0**			**0**
	SEVEN SISTERS							
1115A	DAMS, DYKES AND WEIRS	31,926,879	13,401,995	16,705,443	(3,303,448)	(24.65)	55.0	(60,063)
1115B	POWERHOUSE	13,653,945	6,956,147	8,791,628	(1,835,481)	(26.39)	52.5	(34,962)
1115C	POWERHOUSE RENOVATIONS	578,473	29,276	47,350	(18,074)	(61.74)	38.2	(473)
1115D	SPILLWAY	2,940,065	1,549,466	1,738,916	(189,450)	(12.23)	42.8	(4,426)
1115E	WATER CONTROL SYSTEMS	4,520,291	2,110,166	3,169,768	(1,059,602)	(50.21)	48.1	(22,029)
1115F	ROADS AND SITE IMPROVEMENTS	205,641	120,698	157,505	(36,807)	(30.50)	41.5	(887)
1115G	TURBINES AND GENERATORS	54,449,323	14,363,645	16,740,788	(2,377,143)	(16.55)	45.5	(52,245)
1115H	GOVERNORS AND EXCITATION SYSTEM	290,552	28,536	29,305	(769)	(2.69)	45.2	(17)
1115L	LICENCE RENEWAL							
1115P	A/C ELECTRICAL POWER SYSTEMS	11,924,230	4,402,328	5,724,619	(1,322,291)	(30.04)	40.1	(32,975)
1115Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,960,007	2,511,949	2,975,298	(463,349)	(18.45)	15.5	(29,894)
1115R	AUXILIARY STATION PROCESSES	8,512,853	2,255,498	3,464,996	(1,209,498)	(53.62)	39.6	(30,543)
1115X	SUPPORT BUILDINGS	608,294	152,183	204,918	(52,735)	(34.65)	48.0	(1,099)
1115W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SEVEN SISTERS	**134,570,553**	**47,881,887**	**59,750,533**	**(11,868,646)**	**(24.79)**		**(269,612)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION (1)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (2)	CALCULATED ACCRUED DEPRECIATION (3)	BOOK ACCUMULATED DEPRECIATION (4)	ACCUMULATED DEPRECIATION VARIANCE AMOUNT (5) = (3)-(4)	ACCUMULATED DEPRECIATION VARIANCE PERCENT (6) = (5)/(3)	PROBABLE REMAINING LIFE (7)	ANNUAL PROVISION FOR TRUE-UP (8)=(5)/(7)
	SLAVE FALLS							
1120A	DAMS, DYKES AND WEIRS	954,684	115,097	119,419	(4,322)	(3.75)	57.0	(76)
1120B	POWERHOUSE	45,692,194	8,378,514	8,824,065	(445,551)	(5.32)	56.9	(7,830)
1120C	POWERHOUSE RENOVATIONS							*
1120D	SPILLWAY	1,241,273	138,156	146,272	(8,116)	(5.87)	53.8	(151)
1120E	WATER CONTROL SYSTEMS	318,933	44,820	56,956	(12,136)	(27.08)	52.0	(233)
1120F	ROADS AND SITE IMPROVEMENTS	37,971,797	2,830,096	2,320,038	510,058	18.02	45.3	11,260
1120G	TURBINES AND GENERATORS	12,246,529	2,588,166	2,622,376	(34,210)	(1.32)	46.3	(739)
1120H	GOVERNORS AND EXCITATION SYSTEM	336,652	18,757	20,980	(2,223)	(11.85)	46.9	(47)
1120L	LICENCE RENEWAL							*
1120P	A/C ELECTRICAL POWER SYSTEMS	21,631,850	3,447,054	3,766,359	(319,305)	(9.26)	46.2	(6,911)
1120Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,446,295	634,633	614,152	20,481	3.23	21.7	944
1120R	AUXILIARY STATION PROCESSES	5,288,154	446,038	410,993	35,045	7.86	43.6	804
1120X	SUPPORT BUILDINGS	3,306,577	692,533	391,664	300,869	43.44	48.8	6,165
1120W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SLAVE FALLS	**133,434,938**	**19,333,864**	**19,293,273**	**40,591**	**0.21**		**3,184**
	PINE FALLS							
1125A	DAMS, DYKES AND WEIRS	18,301,512	3,042,347	3,373,554	(331,207)	(10.89)	74.4	(4,452)
1125B	POWERHOUSE	10,060,843	5,156,968	5,899,390	(742,422)	(14.40)	62.4	(11,898)
1125C	POWERHOUSE RENOVATIONS	121,809	5,025	8,933	(3,908)	(77.77)	38.5	(102)
1125D	SPILLWAY	93,376	8,276	9,221	(945)	(11.42)	67.0	(14)
1125E	WATER CONTROL SYSTEMS	3,660,833	1,937,556	2,674,651	(737,095)	(38.04)	48.3	(15,261) ****
1125F	ROADS AND SITE IMPROVEMENTS	1,180,058	1,021,333	1,213,586	(192,253)	(18.82)	31.1	(6,182)
1125G	TURBINES AND GENERATORS	9,318,154	5,751,516	6,336,912	(585,396)	(10.18)	29.4	(19,911)
1125H	GOVERNORS AND EXCITATION SYSTEM							*
1125L	LICENCE RENEWAL							*
1125P	A/C ELECTRICAL POWER SYSTEMS	5,096,978	2,186,558	2,569,620	(383,062)	(17.52)	44.0	(8,706)
1125Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	3,881,573	1,329,024	1,486,418	(157,394)	(11.84)	17.8	(8,842)
1125R	AUXILIARY STATION PROCESSES	3,976,778	1,427,852	2,058,171	(630,319)	(44.14)	37.6	(16,764)
1125X	SUPPORT BUILDINGS	336,412	111,417	122,122	(10,705)	(9.61)	45.4	(236)
1125W	SUPPORT BUILDING RENOVATIONS							*
1125Z	COMMUNITY DEVELOPMENT COSTS ***	26,531,770	1,467,298	1,457,155	10,143	0.69	73.7	**
	TOTAL PINE FALLS	**82,560,097**	**23,445,170**	**27,209,733**	**(3,764,563)**	**(16.06)**		**(92,367)**
	MCARTHUR FALLS							
1130A	DAMS, DYKES AND WEIRS	6,837,356	1,705,681	1,881,776	(176,095)	(10.32)	74.3	(2,370)
1130B	POWERHOUSE	9,358,105	4,748,082	5,321,399	(573,317)	(12.07)	64.1	(8,944)
1130C	POWERHOUSE RENOVATIONS	405,461	16,725	29,734	(13,009)	(77.78)	38.5	(338)
1130D	SPILLWAY	2,417,504	1,679,846	1,815,242	(135,396)	(8.06)	29.6	(4,574)
1130E	WATER CONTROL SYSTEMS	11,703,203	4,223,710	5,994,290	(1,770,580)	(41.92)	46.6	(37,995)
1130F	ROADS AND SITE IMPROVEMENTS	235,262	128,513	146,060	(17,547)	(13.65)	28.8	(609)
1130G	TURBINES AND GENERATORS	5,379,618	4,473,549	4,887,739	(414,190)	(9.26)	15.9	(26,050)
1130H	GOVERNORS AND EXCITATION SYSTEM	119,315	43,704	48,419	(4,715)	(10.79)	33.6	(140)
1130L	LICENCE RENEWAL							*
1130P	A/C ELECTRICAL POWER SYSTEMS	2,521,761	1,736,966	1,995,628	(258,662)	(14.89)	36.8	(7,029)
1130Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,275,876	855,314	948,698	(93,384)	(10.92)	15.4	(6,064)
1130R	AUXILIARY STATION PROCESSES	3,616,031	1,280,768	1,807,227	(526,459)	(41.10)	38.2	(13,782)
1130X	SUPPORT BUILDINGS							
1130W	SUPPORT BUILDING RENOVATIONS							
	TOTAL MCARTHUR FALLS	**43,869,489**	**20,892,858**	**24,876,211**	**(3,983,353)**	**(19.07)**		**(107,895)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	KELSEY							
1135A	DAMS, DYKES AND WEIRS	9,296,418	2,595,620	1,995,524	600,096	23.12	77.8	7,713
1135B	POWERHOUSE	71,294,313	13,890,995	10,733,548	3,157,447	22.73	80.0	39,468
1135C	POWERHOUSE RENOVATIONS							*
1135D	SPILLWAY	7,196,926	3,605,569	2,682,256	923,313	25.61	40.8	22,630
1135E	WATER CONTROL SYSTEMS	35,342,564	5,404,463	5,265,558	138,905	2.57	55.6	2,498
1135F	ROADS AND SITE IMPROVEMENTS	12,310,412	4,206,331	3,327,740	878,591	20.89	29.6	29,682
1135G	TURBINES AND GENERATORS	146,383,857	12,393,983	7,088,935	5,305,048	42.80	54.5	97,340
1135H	GOVERNORS AND EXCITATION SYSTEM	6,948,606	465,319	299,117	166,202	35.72	46.9	3,544
1135L	LICENCE RENEWAL							*
1135P	A/C ELECTRICAL POWER SYSTEMS	40,494,515	3,918,433	1,709,859	2,208,574	56.36	48.6	45,444
1135Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	13,650,816	3,423,378	2,694,420	728,958	21.29	18.1	40,274
1135R	AUXILIARY STATION PROCESSES	9,929,302	2,902,006	2,947,898	(45,892)	(1.58)	36.8	(1,247)
1135X	SUPPORT BUILDINGS	13,448,502	2,625,725	1,989,351	636,374	24.24	52.6	12,098
1135W	SUPPORT BUILDING RENOVATIONS	1,598,817	151,872	303,374	(151,502)	(99.76)	18.3	(8,279)
	TOTAL KELSEY	**367,895,048**	**55,583,694**	**41,037,582**	**14,546,112**	**26.17**		**291,166**
	GRAND RAPIDS							
1140A	DAMS, DYKES AND WEIRS	56,613,946	20,375,922	22,287,282	(1,911,360)	(9.38)	69.8	(27,383)
1140B	POWERHOUSE	24,506,522	10,635,800	11,674,816	(1,039,016)	(9.77)	67.7	(15,347)
1140C	POWERHOUSE RENOVATIONS	31,603	2,469	4,823	(2,354)	(95.35)	37.6	(63)
1140D	SPILLWAY	5,451,760	3,155,841	3,370,471	(214,630)	(6.80)	37.8	(5,678)
1140E	WATER CONTROL SYSTEMS	15,982,492	10,002,476	13,943,141	(3,940,665)	(39.40)	41.6	(94,728)
1140F	ROADS AND SITE IMPROVEMENTS	2,581,475	2,045,769	2,275,494	(229,725)	(11.23)	15.5	(14,821)
1140G	TURBINES AND GENERATORS	113,213,625	35,395,791	36,013,270	(617,479)	(1.74)	43.0	(14,360)
1140H	GOVERNORS AND EXCITATION SYSTEM	1,922,915	73,351	65,897	7,454	10.16	48.2	155 **
1140L	LICENCE RENEWAL	83,122,204	4,106,639	4,023,652	82,987	2.02	47.5	**
1140P	A/C ELECTRICAL POWER SYSTEMS	8,240,545	3,538,618	4,032,021	(493,403)	(13.94)	36.5	(13,518)
1140Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,690,245	3,714,309	4,000,352	(286,043)	(7.70)	12.1	(23,640)
1140R	AUXILIARY STATION PROCESSES	12,334,108	2,318,082	3,299,269	(981,187)	(42.33)	42.9	(22,872)
1140X	SUPPORT BUILDINGS	8,700,819	3,104,976	3,123,329	(18,353)	(0.59)	43.8	(419) **
1140W	SUPPORT BUILDING RENOVATIONS	6,828,234	1,243,309	1,052,948	190,361	15.31	16.3	11,679
1140Z	COMMUNITY DEVELOPMENT COSTS ***	135,205,073	17,970,822	23,917,914	(5,947,092)	(33.09)	68.7	(86,566)
	TOTAL GRAND RAPIDS	**479,425,566**	**117,684,174**	**133,084,678**	**(15,400,504)**	**(13.09)**		**(307,561)**
	KETTLE							
1145A	DAMS, DYKES AND WEIRS	45,280,663	16,858,712	18,812,620	(1,953,908)	(11.59)	79.6	(24,547)
1145B	POWERHOUSE	146,313,138	53,948,133	60,221,797	(6,273,664)	(11.63)	79.8	(78,617)
1145C	POWERHOUSE RENOVATIONS							*
1145D	SPILLWAY	25,406,960	13,345,006	14,521,245	(1,176,239)	(8.81)	41.8	(28,140)
1145E	WATER CONTROL SYSTEMS	19,033,816	11,499,432	16,006,736	(4,507,304)	(39.20)	33.7	(133,748)
1145F	ROADS AND SITE IMPROVEMENTS	556,723	34,307	33,226	1,081	3.15	47.2	23
1145G	TURBINES AND GENERATORS	99,163,384	44,155,497	42,015,133	2,140,364	4.85	35.1	60,979
1145H	GOVERNORS AND EXCITATION SYSTEM	6,930,643	2,786,039	2,924,493	(138,454)	(4.97)	33.0	(4,196)
1145L	LICENCE RENEWAL							*
1145P	A/C ELECTRICAL POWER SYSTEMS	38,779,613	3,809,914	3,020,872	789,042	20.71	49.3	16,005
1145Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	16,263,031	9,435,571	9,901,036	(465,465)	(4.93)	14.5	(32,101)
1145R	AUXILIARY STATION PROCESSES	19,306,615	7,354,434	10,172,476	(2,818,042)	(38.32)	38.5	(73,196)
1145X	SUPPORT BUILDINGS	2,456,258	119,642	41,873	77,769	65.00	60.7	1,281
1145W	SUPPORT BUILDING RENOVATIONS							
	TOTAL KETTLE	**419,490,845**	**163,346,687**	**177,671,508**	**(14,324,821)**	**(8.77)**		**(296,256)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	LAURIE RIVER							
1150A	DAMS, DYKES AND WEIRS	355,538	219,898	160,937	58,961	26.81	20.2	2,919
1150B	POWERHOUSE	7,664,146	3,004,975	2,400,365	604,610	20.12	20.2	29,931
1150C	POWERHOUSE RENOVATIONS							*
1150D	SPILLWAY	870,000	470,299	361,707	108,592	23.09	19.9	5,457
1150E	WATER CONTROL SYSTEMS	458,033	239,069	181,641	57,428	24.02	20.0	2,871
1150F	ROADS AND SITE IMPROVEMENTS	1,441,914	775,043	591,840	183,203	23.64	18.7	9,797
1150G	TURBINES AND GENERATORS	4,603,136	1,507,792	1,250,829	256,963	17.04	20.1	12,784
1150H	GOVERNORS AND EXCITATION SYSTEM	882,653	240,501	210,242	30,259	12.58	20.1	1,505
1150L	LICENCE RENEWAL							*
1150P	A/C ELECTRICAL POWER SYSTEMS	1,441,945	706,396	548,644	157,752	22.33	19.8	7,967
1150Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,220,047	880,232	723,194	157,038	17.84	7.0	22,434
1150R	AUXILIARY STATION PROCESSES	308,504	156,189	125,709	30,480	19.51	18.6	1,639
1150X	SUPPORT BUILDINGS	355,919	203,578	154,615	48,964	24.05	19.8	2,473
1150W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL LAURIE RIVER	**19,601,835**	**8,403,972**	**6,709,722**	**1,694,250**	**20.16**		**99,778**
	JENPEG							
1155A	DAMS, DYKES AND WEIRS	16,438,690	4,072,721	4,745,111	(672,390)	(16.51)	89.8	(7,488)
1155B	POWERHOUSE	76,905,294	24,830,760	25,902,609	(1,071,849)	(4.32)	85.3	(12,566)
1155C	POWERHOUSE RENOVATIONS	26,446	1,091	1,164	(73)	(6.65)	38.5	**
1155D	SPILLWAY	14,942,733	6,946,493	7,090,366	(143,873)	(2.07)	46.2	(3,114)
1155E	WATER CONTROL SYSTEMS	17,167,202	9,492,821	12,092,757	(2,599,936)	(27.39)	33.4	(77,842)
1155F	ROADS AND SITE IMPROVEMENTS	1,563,205	845,491	899,601	(54,110)	(6.40)	25.7	(2,106)
1155G	TURBINES AND GENERATORS	91,716,371	45,717,039	44,027,069	1,689,970	3.70	32.6	51,840
1155H	GOVERNORS AND EXCITATION SYSTEM							*
1155L	LICENCE RENEWAL							*
1155P	A/C ELECTRICAL POWER SYSTEMS	21,641,608	13,269,783	14,316,375	(1,046,592)	(7.89)	24.9	(42,032)
1155Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	3,606,713	2,449,765	2,537,369	(87,604)	(3.58)	9.7	(9,031)
1155R	AUXILIARY STATION PROCESSES	13,685,752	4,107,113	5,581,430	(1,474,317)	(35.90)	39.1	(37,706)
1155X	SUPPORT BUILDINGS	7,885,397	2,880,052	2,897,007	(16,955)	(0.59)	43.4	(391)
1155W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL JENPEG	**265,579,412**	**114,613,129**	**120,090,857**	**(5,477,728)**	**(4.78)**		**(140,436)**
	LAKE WINNIPEG REGULATION							
1160A	DAMS, DYKES AND WEIRS	110,416,014	31,012,331	37,195,119	(6,182,788)	(19.94)	93.4	(66,197)
1160L	LICENCE RENEWAL	250,000	7,500	5,500	2,000	26.67	48.5	41
1160Z	COMMUNITY DEVELOPMENT COSTS ***	436,787,857	83,190,304	89,681,066	(6,490,762)	(7.80)	69.0	**
	TOTAL LAKE WINNIPEG REGULATION	**547,453,871**	**114,210,135**	**126,881,685**	**(12,671,550)**	**(11.09)**		**(66,156)**
	CHURCHILL RIVER DIVERSION							
1165A	DAMS, DYKES AND WEIRS	120,816,679	36,069,807	36,151,776	(81,969)	(0.23)	91.1	(900)
1165D	SPILLWAY	59,622,870	26,498,574	26,015,124	483,450	1.82	47.7	10,135
1165E	WATER CONTROL SYSTEMS	18,858,667	10,583,046	13,850,625	(3,267,579)	(30.88)	33.0	(99,018)
1165F	ROADS AND SITE IMPROVEMENTS	7,284,036	4,761,642	4,896,073	(134,431)	(2.82)	20.4	(6,590)
1165L	LICENCE RENEWAL							*
1165P	A/C ELECTRICAL POWER SYSTEMS	1,710,889	1,105,208	1,153,461	(48,253)	(4.37)	22.9	(2,107)
1165Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,541,737	1,398,970	1,374,377	24,593	1.76	4.2	5,856
1165R	AUXILIARY STATION PROCESSES	1,864,257	492,685	661,280	(168,595)	(34.22)	38.5	(4,379)
1165X	SUPPORT BUILDINGS	79,309	9,880	9,018	862	8.72	57.6	15
1165W	SUPPORT BUILDING RENOVATIONS							
1165Z	COMMUNITY DEVELOPMENT COSTS ***	351,065,147	76,145,342	86,834,635	(10,689,293)	(14.04)	70.9	(150,766)
	TOTAL CHURCHILL RIVER DIVERSION	**562,843,590**	**157,065,154**	**170,946,369**	**(13,881,215)**	**(8.84)**		**(247,753)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE		PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
					AMOUNT	PERCENT		
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	LONG SPRUCE							
1170A	DAMS, DYKES AND WEIRS	65,392,344	20,390,328	21,155,780	(765,452)	(3.75)	86.2	(8,880)
1170B	POWERHOUSE	143,800,935	45,283,496	46,995,513	(1,712,017)	(3.78)	85.9	(19,930)
1170C	POWERHOUSE RENOVATIONS							*
1170D	SPILLWAY	42,273,617	19,198,593	19,485,540	(286,947)	(1.49)	47.0	(6,105)
1170E	WATER CONTROL SYSTEMS	57,946,281	33,730,154	46,254,138	(12,523,984)	(37.13)	30.6	(409,281)
1170F	ROADS AND SITE IMPROVEMENTS	1,376,630	745,263	790,381	(45,118)	(6.05)	25.8	(1,749)
1170G	TURBINES AND GENERATORS	143,328,643	88,245,775	86,535,183	1,710,592	1.94	26.4	64,795
1170H	GOVERNORS AND EXCITATION SYSTEM	145,844	33,562	34,739	(1,177)	(3.51)	39.5	(30)
1170L	LICENCE RENEWAL							*
1170P	A/C ELECTRICAL POWER SYSTEMS	30,610,740	19,418,411	20,941,915	(1,523,504)	(7.85)	23.5	(64,830)
1170Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	13,111,957	4,895,363	4,968,395	(73,032)	(1.49)	17.0	(4,296)
1170R	AUXILIARY STATION PROCESSES	12,385,777	6,137,214	8,340,714	(2,203,500)	(35.90)	29.9	(73,696)
1170X	SUPPORT BUILDINGS	160,484	29,181	29,547	(366)	(1.25)	54.3	(7)
1170W	SUPPORT BUILDING RENOVATIONS	205,681	28,281	29,224	(943)	(3.33)	17.5	**
	TOTAL LONG SPRUCE	**510,738,934**	**238,135,621**	**255,561,069**	**(17,425,448)**	**(7.32)**		**(524,008)**
	LIMESTONE							
1175A	DAMS, DYKES AND WEIRS	33,287,049	6,839,262	6,948,969	(109,707)	(1.60)	98.3	(1,116)
1175B	POWERHOUSE	461,590,745	94,479,025	96,169,680	(1,690,655)	(1.79)	98.4	(17,182)
1175C	POWERHOUSE RENOVATIONS							*
1175D	SPILLWAY	201,416,380	60,215,928	60,573,556	(357,628)	(0.59)	58.3	(6,134)
1175E	WATER CONTROL SYSTEMS	116,325,934	44,206,880	59,122,248	(14,915,368)	(33.74)	42.6	(350,126)
1175F	ROADS AND SITE IMPROVEMENTS	17,384,603	7,999,421	8,304,641	(305,220)	(3.82)	29.1	(10,489)
1175G	TURBINES AND GENERATORS	404,329,629	166,562,147	157,214,379	9,347,768	5.61	37.5	249,274
1175H	GOVERNORS AND EXCITATION SYSTEM	16,598,509	8,077,790	8,287,095	(209,305)	(2.59)	27.9	(7,502)
1175L	LICENCE RENEWAL							*
1175P	A/C ELECTRICAL POWER SYSTEMS	144,588,941	64,574,015	69,759,355	(5,185,340)	(8.03)	32.7	(158,573)
1175Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	8,782,898	5,940,180	6,142,216	(202,036)	(3.40)	9.7	(20,828)
1175R	AUXILIARY STATION PROCESSES	36,388,654	14,217,453	19,242,169	(5,024,716)	(35.34)	32.5	(154,607)
1175X	SUPPORT BUILDINGS	5,707,366	2,024,505	1,995,437	29,068	1.44	44.0	661
1175W	SUPPORT BUILDING RENOVATIONS	652,644	124,319	124,711	(392)	(0.32)	16.5	**
	TOTAL LIMESTONE	**1,447,053,352**	**475,260,925**	**493,884,457**	**(18,623,532)**	**(3.92)**		**(476,622)**
	WUSKWATIM							
1180A	DAMS, DYKES AND WEIRS	4,694,366	40,881	66,472	(25,591)	(62.60)	119.7	(214)
1180B	POWERHOUSE	18,227,672	174,955	256,744	(81,789)	(46.75)	119.7	(683)
1180C	POWERHOUSE RENOVATIONS							*
1180D	SPILLWAY	2,875,828	44,040	68,024	(23,984)	(54.46)	78.9	(304)
1180E	WATER CONTROL SYSTEMS	3,087,285	73,520	109,857	(36,337)	(49.42)	63.6	(571)
1180F	ROADS AND SITE IMPROVEMENTS	2,495,203	81,244	88,897	(7,653)	(9.42)	48.5	(158)
1180G	TURBINES AND GENERATORS	4,652,074	95,484	127,378	(31,894)	(33.40)	58.9	(542)
1180H	GOVERNORS AND EXCITATION SYSTEM	169,166	5,243	5,989	(746)	(14.22)	48.6	(15)
1180P	A/C ELECTRICAL POWER SYSTEMS	1,691,663	50,745	59,318	(8,573)	(16.89)	53.5	(160)
1180Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,141,873	46,053	89,058	(43,005)	(93.38)	24.1	(1,784)
1180R	AUXILIARY STATION PROCESSES	2,029,996	24,616	90,536	(65,920)	(267.79)	49.5	(1,332)
1180X	SUPPORT BUILDINGS	930,415	21,979	25,301	(3,322)	(15.12)	63.6	(52)
1180W	SUPPORT BUILDING RENOVATIONS							
	TOTAL WUSKWATIM	**41,995,540**	**658,760**	**987,574**	**(328,814)**	**(49.91)**		**(5,816)**
	INFRASTRUCTURE SUPPORTING GENERATION							
1199F	PROVINCIAL ROADS	25,412,921	15,956,840	14,398,428	1,558,412	9.77	21.3	73,165
1199V	TOWN SITE BUILDINGS	82,260,635	27,771,165	22,775,639	4,995,526	17.99	35.9	139,151
1199W	TOWN SITE BUILDING RENOVATIONS	27,027,620	8,124,267	7,474,145	650,122	8.00	13.9	*
1199Y	TOWN SITE OTHER INFRASTRUCTURE	29,155,301	10,245,173	4,725,638	5,519,535	53.87	28.3	195,037
	TOTAL INFRASTRUCTURE SUPPORTING GENERATION	**163,856,477**	**62,097,445**	**49,373,849**	**12,723,596**	**20.49**		**407,353**
	TOTAL HYDRAULIC GENERATION	**5,445,593,386**	**1,688,270,263**	**1,794,265,811**	**(105,995,548)**	**(6.28)**		**(703,166)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION (1)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (2)	CALCULATED ACCRUED DEPRECIATION (3)	BOOK ACCUMULATED DEPRECIATION (4)	ACCUMULATED DEPRECIATION VARIANCE AMOUNT (5) = (3)-(4)	ACCUMULATED DEPRECIATION VARIANCE PERCENT (6) = (5)/(3)	PROBABLE REMAINING LIFE (7)	ANNUAL PROVISION FOR TRUE-UP (8)=(5)/(7)
	THERMAL GENERATION							
	BRANDON UNIT 5 (COAL)							
1205B	POWERHOUSE	11,729,518	9,436,534	8,961,429	475,105	5.03	5.2	91,366
1205C	POWERHOUSE RENOVATIONS	396,538	88,119	66,090	22,029	25.00	5.2	4,236
1205F	ROADS AND SITE IMPROVEMENTS	4,018,549	3,080,059	2,901,743	178,316	5.79	5.2	34,292
1205G	TURBINES AND GENERATORS	19,611,168	14,470,076	13,747,137	722,939	5.00	5.2	139,027
1205H	GOVERNORS AND EXCITATION SYSTEM	2,343,861	1,721,050	1,667,938	53,112	3.09	5.2	10,214
1205J	STEAM GENERATOR AND AUXILIARIES	14,655,599	11,729,865	11,583,564	146,301	1.25	5.2	28,135 **
1205L	LICENCE RENEWAL	2,198,654	488,585	484,127	4,458	0.91	5.2	**
1205P	A/C ELECTRICAL POWER SYSTEMS	8,026,175	6,423,380	6,105,036	318,344	4.96	5.1	62,420
1205Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25,758,061	20,491,436	20,804,835	(313,399)	(1.53)	4.4	(71,227)
1205R	AUXILIARY STATION PROCESSES	47,355,066	36,324,333	34,357,132	1,967,201	5.42	5.1	385,726
1205X	SUPPORT BUILDINGS	7,837,127	5,784,694	5,386,420	398,274	6.88	5.2	76,591
1205W	SUPPORT BUILDING RENOVATIONS							
	TOTAL BRANDON UNIT 5 (COAL)	**143,930,317**	**110,038,131**	**106,065,451**	**3,972,680**	**3.61**		**760,780**
	BRANDON UNITS 6 AND 7							
1210B	POWERHOUSE	14,925,029	2,517,130	3,326,364	(809,234)	(32.15)	63.5	(12,744)
1210C	POWERHOUSE RENOVATIONS	144,571	6,678	8,409	(1,731)	(25.93)	38.3	(45)
1210G	TURBINES AND GENERATORS	11,222,428	2,159,791	2,949,523	(789,732)	(36.57)	49.6	(15,922)
1210H	GOVERNORS AND EXCITATION SYSTEM							*
1210K	COMBUSTION TURBINE	143,303,747	65,917,166	76,984,957	(11,067,791)	(16.79)	14.6	(758,068)
1210L	LICENCE RENEWAL							*
1210M	COMBUSTION TURBINE OVERHAULS							*
1210P	A/C ELECTRICAL POWER SYSTEMS	6,346,535	1,426,903	1,768,122	(341,219)	(23.91)	43.8	(7,790)
1210Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,295,814	334,352	304,113	30,239	9.04	19.1	1,583
1210R	AUXILIARY STATION PROCESSES	10,639,560	2,312,848	3,546,367	(1,233,519)	(53.33)	40.1	(30,761)
	TOTAL BRANDON UNITS 6 AND 7	**187,877,685**	**74,674,868**	**88,887,855**	**(14,212,987)**	**(19.03)**		**(823,747)**
	SELKIRK							
1215B	POWERHOUSE	6,808,812	3,992,068	6,717,712	(2,725,644)	(68.28)	69.8	(39,049)
1215C	POWERHOUSE RENOVATIONS	451,038	16,132	25,253	(9,121)	(56.54)	38.6	(236)
1215F	ROADS AND SITE IMPROVEMENTS	1,630,443	753,812	1,158,719	(404,907)	(53.71)	37.5	(10,798)
1215G	TURBINES AND GENERATORS	22,750,003	8,291,011	14,850,769	(6,559,758)	(79.12)	49.7	(131,987)
1215H	GOVERNORS AND EXCITATION SYSTEM	17,307	7,321	11,634	(4,313)	(58.91)	28.8	(150)
1215J	STEAM GENERATOR AND AUXILIARIES	51,721,352	12,649,706	17,133,762	(4,484,056)	(35.45)	49.5	(90,587)
1215L	LICENCE RENEWAL							*
1215P	A/C ELECTRICAL POWER SYSTEMS	3,171,700	1,961,181	3,164,610	(1,203,429)	(61.36)	49.9	(24,117)
1215Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	5,286,066	2,985,151	4,396,109	(1,410,958)	(47.27)	14.6	(96,641)
1215R	AUXILIARY STATION PROCESSES	14,897,376	5,405,418	10,468,362	(5,062,944)	(93.66)	41.8	(121,123)
1215X	SUPPORT BUILDINGS	1,033,229	480,033	737,298	(257,265)	(53.59)	52.2	(4,928)
1215W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SELKIRK	**107,767,327**	**36,541,833**	**58,664,226**	**(22,122,393)**	**(60.54)**		**(519,616)**
	TOTAL THERMAL GENERATION	**439,575,329**	**221,254,832**	**253,617,532**	**(32,362,700)**	**(14.63)**		**(582,584)**
	TOTAL GENERATION	**5,885,168,715**	**1,909,525,095**	**2,047,883,343**	**(138,358,248)**	**(7.25)**		**(1,285,750)**
	DIESEL GENERATION							
1300B	BUILDINGS	8,263,526	4,299,498	5,435,792	(1,136,294)	(26.43)	13.1	(86,740) **
1300C	BUILDING RENOVATIONS	17,929	9,505	9,086	419	4.41	7.0	*
1300M	ENGINES AND GENERATORS - OVERHAULS	1,998,461	1,192,879	2,092,372	(899,493)	(75.41)	1.6	***
1300N	ENGINES AND GENERATORS	16,774,955	7,386,263	13,042,057	(5,655,794)	(76.57)	14.6	(387,383)
1300Q	ACCESSORY STATION EQUIPMENT	15,892,750	7,575,507	11,319,359	(3,743,852)	(49.42)	15.2	(246,306)
1300T	FUEL STORAGE AND HANDLING	5,083,046	2,227,849	3,724,492	(1,496,643)	(67.18)	16.1	(92,959)
	TOTAL DIESEL GENERATION	**48,030,666**	**22,691,501**	**35,623,157**	**(12,931,656)**	**(56.99)**		**(813,388)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION (1)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (2)	CALCULATED ACCRUED DEPRECIATION (3)	BOOK ACCUMULATED DEPRECIATION (4)	ACCUMULATED DEPRECIATION VARIANCE AMOUNT (5) = (3)-(4)	ACCUMULATED DEPRECIATION VARIANCE PERCENT (6) = (5)/(3)	PROBABLE REMAINING LIFE (7)	ANNUAL PROVISION FOR TRUE-UP (8)=(5)/(7)
	TRANSMISSION							
2000F	ROADS, TRAILS AND BRIDGES	10,686,118	1,522,374	1,558,816	(36,442)	(2.39)	43.6	(836)
2000G	METAL TOWERS AND CONCRETE POLES	481,955,524	137,668,492	117,832,337	19,836,156	14.41	64.5	307,537
2000J	POLES AND FIXTURES	117,066,069	46,902,069	45,781,675	1,120,394	2.39	38.5	29,101 **
2000K	GROUND LINE TREATMENT	2,297,990	997,647	929,181	68,466	6.86	5.5	**
2000L	OVERHEAD CONDUCTOR AND DEVICES	349,810,506	116,174,012	151,380,725	(35,206,713)	(30.31)	59.8	(588,741)
2000M	UNDERGROUND CABLE AND DEVICES	960,535	679,161	731,355	(52,194)	(7.68)	14.7	(3,551)
2000Z	COMMUNITY DEVELOPMENT COSTS ***	17,625,510	365,319	418,852	(53,533)	(14.65)	77.4	(692)
	TOTAL TRANSMISSION	**980,402,254**	**304,309,074**	**318,632,940**	**(14,323,866)**	**(4.71)**		**(257,181)**
	SUBSTATIONS							
3000B	BUILDINGS	167,465,733	50,901,230	62,935,699	(12,034,469)	(23.64)	49.6	(242,630) **
3000C	BUILDING RENOVATIONS	16,023,446	2,702,989	2,768,723	(65,734)	(2.43)	16.6	**
3000F	ROADS, STEEL STRUCTURES AND CIVIL SITE WORKS	301,966,571	129,476,589	155,273,917	(25,797,328)	(19.92)	34.6	(745,588)
3000J	POLES AND FIXTURES	8,976,505	2,906,933	2,862,084	44,849	1.54	34.2	1,311
3100R	POWER TRANSFORMERS	346,530,004	120,538,576	104,341,044	16,197,532	13.44	34.1	475,001
3100S	OTHER TRANSFORMERS	112,490,470	38,597,410	39,113,400	(515,990)	(1.34)	35.1	(14,701)
3100T	INTERRUPTING EQUIPMENT	210,045,708	85,423,959	71,133,091	14,290,868	16.73	30.3	471,646
3100U	OTHER STATION EQUIPMENT	553,640,228	220,677,495	233,531,016	(12,853,521)	(5.82)	30.4	(422,813)
3100V	ELECTRONIC EQUIPMENT AND BATTERIES	222,763,291	78,524,863	104,250,748	(25,725,885)	(32.76)	19.9	(1,292,758)
3200M	SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	122,026,806	58,181,842	56,949,947	1,231,896	2.12	38.0	32,418
3200N	SYNCHRONOUS CONDENSER OVERHAULS	47,815,173	21,528,379	21,926,203	(397,824)	(1.85)	10.1	**
3200P	HVDC CONVERTER EQUIPMENT	434,607,924	200,877,868	252,425,453	(51,547,585)	(25.66)	19.5	(2,643,466)
3200S	HVDC SERIALIZED EQUIPMENT	213,665,609	152,887,002	179,848,253	(26,961,251)	(17.63)	20.8	(1,296,214)
3200U	HVDC ACCESSORY STATION EQUIPMENT	169,254,248	62,185,861	71,820,161	(9,634,300)	(15.49)	26.3	(366,323)
3200V	HVDC ELECTRONIC EQUIPMENT AND BATTERIES	47,913,305	30,524,639	45,452,340	(14,927,701)	(48.90)	24.0	(621,988)
	TOTAL SUBSTATIONS	**2,975,185,020**	**1,255,935,635**	**1,404,632,079**	**(148,696,444)**	**(11.84)**		**(6,666,104)**
	DISTRIBUTION							
4000A	CONCRETE DUCTLINE AND MANHOLES	70,181,420	16,543,805	17,333,603	(789,798)	(4.77)	43.6	(18,117)
4000C	CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT	7,368,727	861,759	549,371	312,388	36.25	26.5	11,788
4000G	METAL TOWERS	10,853,698	1,714,272	1,635,676	78,596	4.58	52.3	1,503
4000J	POLES AND FIXTURES	668,956,088	235,164,445	291,618,371	(56,453,926)	(24.01)	49.6	(1,138,184)
4000K	GROUND LINE TREATMENT	34,478,470	13,877,134	16,410,452	(2,533,318)	(18.26)	7.8	(324,784)
4000L	OVERHEAD CONDUCTOR AND DEVICES	717,203,040	262,333,839	282,631,667	(20,297,828)	(7.74)	44.6	(455,108)
4000M	UNDERGROUND CABLE AND DEVICES - 66 KV	27,891,495	3,706,658	4,145,427	(438,769)	(11.84)	52.5	(8,358)
4000N	UNDERGROUND CABLE AND DEVICES - PRIMARY	374,567,850	67,876,746	78,442,229	(10,565,483)	(15.57)	50.1	(210,888)
4000P	UNDERGROUND CABLE AND DEVICES - SECONDARY	249,788,828	71,308,835	80,594,930	(9,286,095)	(13.02)	32.8	(283,113)
4000Q	SERIALIZED EQUIPMENT - OVERHEAD	218,784,786	67,241,833	88,347,900	(21,106,067)	(31.39)	34.9	(604,758)
4000R	DSC - HIGH VOLTAGE TRANSFORMERS	25,320,598	1,907,834	1,413,120	494,714	25.93	46.7	10,594
4000S	SERIALIZED EQUIPMENT - UNDERGROUND	213,763,677	68,210,516	77,018,038	(8,807,522)	(12.91)	31.2	(282,292)
4000V	ELECTRONIC EQUIPMENT	739,972	152,768	121,945	30,823	20.18	7.9	3,902
4000W	SERVICES	73,127,688	38,438,302	58,331,604	(19,893,302)	(51.75)	25.1	(792,562)
4000X	STREET LIGHTING	182,346,807	84,899,623	84,563,957	335,666	0.40	26.7	12,572
	TOTAL DISTRIBUTION	**2,875,373,143**	**934,238,369**	**1,083,158,289**	**(148,919,920)**	**(15.94)**		**(4,077,807)**
	METERS							
4900V	METERS - ELECTRONIC	18,913,638	6,304,334	1,405,387	4,898,947	77.71	8.8	556,699
4900Y	METERS - ANALOG	19,622,056	11,265,127	11,286,557	(21,430)	(0.19)	11.1	(1,931)
4900W	METERING EXCHANGES	33,545,519	13,908,623	13,913,673	(5,050)	(0.04)	8.8	
4900Z	METERING TRANSFORMERS	11,244,938	3,012,865	3,892,303	(879,438)	(29.19)	38.7	(22,725)
	TOTAL METERS	**83,326,152**	**34,490,949**	**30,497,921**	**3,993,028**	**11.58**		**532,043**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	COMMUNICATION							
5000B	BUILDINGS	6,955,504	2,274,024	2,947,372	(673,348)	(29.61)	46.5	(14,481)
5000C	BUILDING RENOVATIONS	3,486,352	1,305,730	1,440,484	(134,754)	(10.32)	13.4	(10,056)
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,426,507	3,525,976	(99,469)	(2.90)	59.6	(1,669)
5000G	COMMUNICATION TOWERS	12,362,119	3,715,363	3,350,680	364,683	9.82	42.3	8,621
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	34,203,813	29,139,100	5,064,713	14.81	26.1	194,050
5000J	CARRIER EQUIPMENT	125,921,733	53,806,562	61,816,520	(8,009,958)	(14.89)	12.5	(640,797) **
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,609,032	2,691,962	(82,930)	(3.18)	2.6	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,738,030	4,438,690	1,299,340	22.64	2.7	481,237
5000N	OPERATIONAL DATA NETWORK	18,817,356	8,386,249	8,136,535	249,714	2.98	4.6	**
5000R	POWER SYSTEM CONTROL	14,264,753	6,710,449	8,431,858	(1,721,409)	(25.65)	10.7	(160,879)
	TOTAL COMMUNICATION	**342,908,725**	**122,175,759**	**125,919,176**	**(3,743,417)**	**(3.06)**		**(143,973)**
	MOTOR VEHICLES							
6000E	PASSENGER VEHICLES	1,145,330	471,876	487,352	(15,476)	(3.28)	5.5	(2,814)
6000F	LIGHT TRUCKS	69,461,644	28,139,845	29,754,753	(1,614,908)	(5.74)	6.9	(234,045)
6000G	HEAVY TRUCKS	73,416,587	27,603,941	29,435,263	(1,831,322)	(6.63)	11.6	(157,873)
6000H	CONSTRUCTION EQUIPMENT	21,130,532	5,649,098	8,256,831	(2,607,733)	(46.16)	17.4	(149,870)
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	3,468,440	4,072,604	(604,164)	(17.42)	20.6	(29,328)
6000J	TRAILERS	18,887,911	4,304,614	4,536,914	(232,300)	(5.40)	25.8	(9,004)
6000K	MISCELLANEOUS VEHICLES	6,114,461	1,529,829	2,553,455	(1,023,626)	(66.91)	10.2	(100,356)
	TOTAL MOTOR VEHICLES	**205,776,939**	**71,167,643**	**79,097,171**	**(7,929,528)**	**(11.14)**		**(683,288)**
	BUILDINGS							
8000B	BUILDINGS - GENERAL	103,251,540	31,082,172	29,525,141	1,557,032	5.01	46.1	33,775 **
8000C	BUILDING RENOVATIONS	37,401,024	12,622,499	10,936,091	1,686,408	13.36	13.1	128,733
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	10,946,359	10,816,316	130,043	1.19	94.6	1,375
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	8,759,755	8,539,762	219,993	2.51	39.9	5,514 **
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7	**
	TOTAL BUILDINGS	**421,792,317**	**64,041,944**	**60,434,771**	**3,607,173**	**5.63**		**169,397**
	GENERAL EQUIPMENT							
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3	**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0	**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3	**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9	**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		**0**
	EASEMENTS							**
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8	**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		**0**
	COMPUTER SOFTWARE AND DEVELOPMENT							
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,182,098	68,946,077	(1,763,979)	(2.63)	4.7	(375,315)
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,036,286	6,634,595	(3,598,309)	(118.51)	5.6	(642,555)
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**99,644,893**	**106,830,136**	**(7,185,243)**	**(7.21)**		**(1,104,039)**
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,907,244,608**	**5,381,231,843**	**(473,987,235)**			**(14,330,090)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	WUSKWATIM POWER LIMITED PARTNERSHIP ("WPLP")							
	PROPERTY, PLANT AND EQUIPMENT							
	HYDRAULIC GENERATION							
1181A	WPLP - DAMS, DYKES AND WEIRS	148,498,470	2,014,085	2,094,830	(80,745)	(4.01)	119.4	(676)
1181B	WPLP - POWERHOUSE	569,576,645	7,725,168	8,045,968	(320,800)	(4.15)	119.4	(2,687)
1181C	WPLP - POWERHOUSE RENOVATIONS							*
1181D	WPLP - SPILLWAY	90,639,257	1,844,509	2,141,648	(297,139)	(16.11)	78.5	(3,785)
1181E	WPLP - WATER CONTROL SYSTEMS	98,584,694	2,502,868	3,484,050	(981,182)	(39.20)	63.5	(15,452)
1181F	WPLP - ROADS AND SITE IMPROVEMENTS	79,988,348	2,604,421	2,819,016	(214,595)	(8.24)	48.5	(4,425)
1181G	WPLP - TURBINES AND GENERATORS	149,857,582	4,121,084	4,035,022	86,062	2.09	58.5	1,471
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM	5,167,019	170,512	182,665	(12,153)	(7.13)	48.5	(251)
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS	49,908,667	1,497,110	1,853,786	(356,676)	(23.82)	53.5	(6,667)
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS	37,311,999	2,462,592	2,813,959	(351,367)	(14.27)	23.5	(14,952)
1181R	WPLP - AUXILIARY STATION PROCESSES	66,497,960	1,974,989	2,869,313	(894,324)	(45.28)	48.7	(18,364)
1181X	WPLP - SUPPORT BUILDINGS	29,258,457	742,814	794,301	(51,487)	(6.93)	63.5	(811)
1181W	WPLP - SUPPORT BUILDING RENOVATIONS							*
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND	389,662	6,153	34,187	(28,034)	(455.62)	93.5	(300)
	TOTAL GENERATION	**1,325,678,762**	**27,666,305**	**31,168,746**	**(3,502,441)**	**(12.66)**		**(66,897)**
	SUBSTATIONS							
3081B	WPLP - BUILDINGS	326,268	7,907	7,829	79	0.99	63.5	1
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	1,761,913	58,143	59,583	(1,440)	(2.48)	48.5	(30)
3181R	WPLP - POWER TRANSFORMERS	4,482,057	126,797	163,394	(36,597)	(28.86)	48.8	(750)
3181T	WPLP - INTERRUPTING EQUIPMENT	839,984	27,241	32,599	(5,358)	(19.67)	48.6	(110)
3181U	WPLP - OTHER STATION EQUIPMENT	1,621,291	60,913	66,315	(5,402)	(8.87)	43.5	(124)
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	1,065,222	63,274	81,652	(18,378)	(29.04)	23.6	(779)
	TOTAL SUBSTATIONS	**10,096,734**	**344,275**	**411,371**	**(67,096)**	**(19.49)**		**(1,792)**
	COMMUNICATION							
5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE	150,000	6,285	7,392	(1,107)	(17.61)	33.6	(33)
5081J	WPLP - CARRIER EQUIPMENT	50,000	3,701	6,184	(2,483)	(67.08)	18.6	(134)
	TOTAL COMMUNICATION	**200,000**	**9,986**	**13,575**	**(3,589)**	**(35.94)**		**(166)**
	MOTOR VEHICLES							
6081G	WPLP - HEAVY TRUCKS	46,325	3,401	23,363	(19,962)	(586.95)	17.5	(1,141)
6081H	WPLP - CONSTRUCTION EQUIPMENT	42,012	2,060	923	1,138	55.22	21.6	53
6081J	WPLP - TRAILERS	82,208	2,975	2,568	407	13.67	33.5	12
6081K	WPLP - MISCELLANEOUS VEHICLES	54,399	4,838	5,825	(987)	(20.41)	11.6	(85)
	TOTAL MOTOR VEHICLES	**224,944**	**13,274**	**32,679**	**(19,405)**	**(146.19)**		**(1,161)**
	GENERAL EQUIPMENT							
9081K	WPLP - COMPUTER EQUIPMENT	21,228	6,368	9,591	(3,223)	(50.60)	3.5	(921)
	TOTAL GENERAL EQUIPMENT	**21,228**	**6,368**	**9,591**	**(3,223)**	**(50.60)**		**(921)**
	TOTAL WPLP PROPERTY, PLANT AND EQUIPMENT	**1,336,221,667**	**28,040,208**	**31,635,962**	**(3,595,754)**	**(12.82)**		**(70,937)**
	INTANGIBLE ASSETS							
	TRANSMISSION							
2080F	WPLP - ROADS, TRAILS AND BRIDGES	1,439,812	47,514	58,197	(10,683)	(22.48)	48.5	(220)
2080G	WPLP - METAL TOWERS AND CONCRETE POLES	106,632,518	2,352,580	2,613,013	(260,433)	(11.07)	83.5	(3,119)
2080J	WPLP - POLES AND FIXTURES	430,084	15,624	16,997	(1,373)	(8.79)	53.5	(26)
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES	29,011,058	625,551	758,010	(132,459)	(21.17)	78.5	(1,687)
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND	1,909,456	36,261	44,679	(8,418)	(23.22)	77.5	(109)
	TOTAL TRANSMISSION	**139,422,928**	**3,077,530**	**3,490,895**	**(413,365)**	**(13.43)**		**(5,161)**

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	SUBSTATIONS							
3080B	WPLP - BUILDINGS	11,080,091	266,647	264,222	2,425	0.91	63.5	38
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	44,652,522	1,471,028	1,509,841	(38,813)	(2.64)	48.5	(800)
3180R	WPLP - POWER TRANSFORMERS	4,272,536	119,776	151,476	(31,700)	(26.47)	48.8	(650)
3180S	WPLP - OTHER TRANSFORMERS	31,309,273	1,074,381	1,556,083	(481,702)	(44.84)	48.5	(9,932)
3180T	WPLP - INTERRUPTING EQUIPMENT	25,624,773	819,006	979,829	(160,823)	(19.64)	48.6	(3,309)
3180U	WPLP - OTHER STATION EQUIPMENT	19,617,296	731,605	797,278	(65,673)	(8.98)	43.5	(1,510)
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	19,286,904	1,135,028	1,468,111	(333,083)	(29.35)	23.7	(14,054)
	TOTAL SUBSTATIONS	**155,843,395**	**5,617,471**	**6,726,839**	**(1,109,368)**	**(19.75)**		**(30,217)**
	DISTRIBUTION							
4080J	WPLP - POLES AND FIXTURES	187,208	4,293	4,986	(693)	(16.15)	63.9	(11)
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES	315,541	8,835	9,882	(1,047)	(11.85)	58.8	(18)
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY	819,462	21,227	22,302	(1,075)	(5.06)	58.5	(18)
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND	29,630	1,193	1,239	(46)	(3.81)	40.5	(1)
	TOTAL DISTRIBUTION	**1,351,840**	**35,548**	**38,409**	**(2,861)**	**(8.05)**		**(48)**
	COMMUNICATION							
5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE	4,463,440	187,025	220,436	(33,411)	(17.86)	33.6	(994)
5080J	WPLP - CARRIER EQUIPMENT	2,508,284	185,543	311,283	(125,740)	(67.77)	18.6	(6,760)
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING	212,713	41,878	35,076	6,802	16.24	6.5	1,047
5080N	WPLP - OPERATIONAL DATA NETWORK	440,117	86,648	99,932	(13,284)	(15.33)	6.5	(2,044)
	TOTAL COMMUNICATION	**7,624,554**	**501,094**	**666,727**	**(165,633)**	**(33.05)**		**(8,752)**
	EASEMENTS							
A180A	WPLP - EASEMENTS	796,640	13,009	12,601	408	3.14	73.8	**
	TOTAL EASEMENTS	**796,640**	**13,009**	**12,601**	**408**	**3.14**		**0**
	TOTAL WPLP INTANGIBLE ASSETS	**305,039,358**	**9,244,652**	**10,935,471**	**(1,690,819)**	**(18.29)**		**(44,178)**
	TOTAL WUSKWATIM POWER LIMITED PARTNERSHIP	**1,641,261,025**	**37,284,860**	**42,571,433**	**(5,286,573)**			**(115,114)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUAL RATES APPLICABLE TO
DEPRECIABLE ASSETS IN SERVICE
AS OF MARCH 31, 2014

Prepared by:

Excellence Delivered **As Promised**

MANITOBA HYDRO
Winnipeg, Manitoba

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES APPLICABLE TO DEPRECIABLE ASSETS IN SERVICE AS OF MARCH 31, 2014

GANNETT FLEMING CANADA ULC

Calgary, Alberta

Gannett Fleming

Excellence Delivered ***As Promised***

January 13, 2015

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Attention: Mr. Darren Rainkie
Vice-President, Finance and Regulatory

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric generation, transmission, substation, distribution and general plant systems of Manitoba Hydro and the Wuskwatim Power Limited Partnership as of March 31, 2014. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of March 31, 2014. The depreciation rates are based on the straight-line method, equal life group procedure applied on a whole life basis, with any accumulated depreciation variances amortized over the estimated remaining life of the assets.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK/hac
Project 058390.400

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MANITOBA HYDRO
2014 DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Manitoba Hydro's ("Company") request, Gannett Fleming Canada ULC ("Gannett Fleming") conducted a depreciation study related to the generation, transmission, substation, distribution and general plant accounts as of March 31, 2014. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking objectives.

The depreciation rates are based on the straight line method using the equal life group ("ELG") procedure and were applied on a whole life basis based on attained ages and estimated average service lives. The depreciation calculations provided herein do not include any provision for cost of removal. Variances between the calculated accrued depreciation and the book accumulated depreciation as of March 31, 2014 are amortized over the remaining life of assets.

As discussed in the last review of depreciation rates, the use of the ELG procedure and the removal of net negative salvage from the depreciation rate calculations are consistent with Manitoba Hydro's planned implementation of International Financial Reporting Standards ("IFRS").

Gannett Fleming recommends the annual depreciation accrual rates for the electric plant in service as of March 31, 2014 as presented in Tables 1, 1A, 2 and 2A of the study. Supporting data and calculations are also provided under separate cover. These rates are effective for Manitoba Hydro on April 1, 2015 upon its transition to IFRS.

This study results in an annual depreciation expense accrual of $319.2 million when applied to depreciable plant balances as of March 31, 2014. The report study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST MARCH 31, 2014 $'s	ELG ANNUAL ACCRUAL %'s	ELG ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
GENERATION			
HYDRO	5,445,593,386	1.54	83,954,010
THERMAL	439,575,329	3.44	15,106,757
DIESEL	48,030,666	4.03	1,937,288
TRANSMISSION	980,402,254	1.28	12,587,905
SUBSTATIONS	2,975,185,020	2.40	71,322,345
DISTRIBUTION	2,875,373,143	1.98	57,047,472
GENERAL	1,466,265,753	5.27	77,235,884
TOTAL PLANT IN SERVICE	**14,230,425,551**	**2.24**	**319,191,661**

PART I. INTRODUCTION

MANITOBA HYDRO
DEPRECIATION STUDY
PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Manitoba Hydro, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of Manitoba Hydro's and the Wuskwatim Power Limited Partnership's electric generation, transmission, substation, distribution and general plant assets as of March 31, 2014. These rates will be effective on April 1, 2015 upon Manitoba Hydro's transition to IFRS. The rates and amounts are based on the straight-line whole life method of depreciation incorporating the ELG procedure with a separate amortization of the variance between the book depreciation reserve and the calculated accrued depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric plant in service.

The service life estimates resulting from the study were based on: informed professional engineering judgment which incorporated analyses of historical plant retirement data as recorded through March 31, 2014; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric industry, including knowledge of service life estimates used for other electric utilities.

PLAN OF REPORT

Part I. Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used in the service life studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. The Supporting Documents to this study include: Part V. Service Life Statistics, which presents the results of the retirement rate analysis and Part VI. Detailed Depreciation Calculations, which present the detailed tabulations of annual and accrued depreciation. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix A of this report.

BASIS OF THE STUDY

Depreciation

For most accounts, the annual and accrued depreciation were calculated by the straight-line method using the equal life group procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives. Variances between the calculated accrued depreciation or amortization and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Gannett Fleming has determined an amortization amount to true-up the present variance with the calculated accrued depreciation, (“theoretical reserve”), over the composite remaining life of each account. Tables 2 and 2A presented in Part IV of the report sets forth the amortization of the reserve variance at the account level. This adjustment mechanism, whether determined separately as an amortization amount or incorporated in the calculation of remaining life accruals, is widely-accepted. An explanation of the monitoring of the accumulated depreciation reserve and the calculation of the true-up provision is presented beginning on page III-5 of the report.

The straight-line method, equal life group procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its use given the company’s requirement to comply with IFRS. Amortization accounting is used for certain accounts that contain a large volume of small dollar value assets where the effort required to maintain detailed records is not warranted. Many electric utilities in North America have received approval to adopt amortization accounting for these types of accounts.

Service Life Estimates

The service life estimates used in the depreciation and amortization calculations are based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry and comparisons of the service life estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for hydroelectric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital activity varies significantly from the assumptions included in this study.

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight-line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and relative height of the modes. The left-moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical-moded curves are those in which the greatest frequency of retirement occurs at average service life. The right-moded curves are those in which the greatest frequency occurs to the right of, or after, the average service life. The origin-moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age 0. The letter designation of each family of curves (L, S, R or O) represents the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report.

Survivor Curve Judgments

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and on the knowledge Gannett Fleming developed through the completion of numerous electric utility studies.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Gannett Fleming in the determination of the average service life estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

Generation Accounts

Gannett Fleming developed unique depreciation rate calculations for each of the hydraulic generation plants in recognition of the estimated specific life spans for each plant. However, the average service life estimates were developed through a retirement rate analysis which was prepared on the basis of a grouping of the plant accounting data at an account level related to the combined databases from all hydraulic generation sites. Therefore, the analyses presented in Section IV of the Supporting Documents and as discussed below, are based on the combined data from all locations for each account.

Hydraulic Accounts

The investment in Manitoba Hydro's hydraulic generation is captured in Account Groups which are individually tracked by geographic site. The plant accounting information for each of the groups is aggregated from the information related to each of the geographic sites to facilitate review and to provide for a statistically relevant population of retirement activity to study. As such, the depreciation rates use a common average service life estimate for each of the account groupings.

Account Grouping 000A – Dams, Dykes and Weirs, represents 10.3% of the hydraulic generation and 3.9% of the depreciable assets studied. The investment in this account relates mainly to the geotechnical components, including both concrete and earthen structures. Company management and operational staff have indicated that these structures were engineered to a high standard in order to provide an increased level of safety and longevity. Additionally, the operational staff view that the environmental conditions to which the investment in this account is exposed, will result in a slower erosion of the physical structures than may be witnessed by other similar Canadian dams. As such, it is expected that the investment in this account would have a longer average life expectation than many of the peer group of Canadian electric generation utilities. Additionally, on a yearly basis, the company makes a significant level of investment on dam safety programs throughout its system.

The retirement rate analysis as presented on pages V-3 through V-5 in the Supporting Documents has reviewed the retirement history from 1923 through 2014.

The currently approved Iowa curve related to these assets is the Iowa 125-R4. Based on the retirement rate analysis and on the expectations of operational staff, Gannett Fleming recommends to retain the current Iowa 125-R4 retirement dispersion curve. With this recommendation, the average service life characteristics of the Dams, Dykes and Weirs account will be matched to the estimated retirement dispersion related to the Powerhouse account.

Account Grouping 000B – Powerhouse, represents 19.2% of the hydraulic generation assets and 7.3% of the depreciable assets studied. The investment in this account relates to the powerhouses and civil buildings, including the structural and concrete components.

With the exception of the Grand Rapids generation site, the hydraulic generation powerhouses are part of the physical concrete dam structure. The Grand Rapids powerhouse is located physically behind the dam in a separate structure. Based on the retirement rate analysis as presented on pages V-7 through V-9 in the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends the continued use of the Iowa 125-R4 for the civil assets related to the hydraulic assets.

Account Grouping 000D – Spillway, represents 7.1% of the hydraulic generation assets and 2.7% of the depreciable assets studied. The typical average service lives for spillways within the Canadian electric generation industry range from 60 to 100 years. Since the last study this account has continued the trend of minimal retirement experience as indicated in the retirement rate analysis presented on pages V-11 through V-13 of the Supporting Documents. Based on the continued trend of limited retirement experience and the affirmation of operational staff, Gannett Fleming recommends an extension of the average service life estimate for this account to an Iowa 80-R3 curve.

Account Grouping 000E – Water Control Systems, represents 6.1% of the hydraulic generation assets and 2.3% of the depreciated assets studied. The investment in this account includes the investment related to gates, guides and hoists. These types of assets are subjected to wear and tear and will require replacement over the life of the generation plant.

Interviews with company operational staff have indicated an expectation of a 65-year life, which would represent a 15-year extension to the currently approved 50-year life. Based on the retirement rate analysis as presented on pages V-15 through V-17 of the Supporting Documents, Gannett Fleming agrees that a life extension is warranted. While the retirement rate analysis may suggest that a life extension of more than 15 years is warranted, the comments of the operational staff indicated a life of 65 years. It is also noted that a 15-year average service life extension represents a 30% increase. Based on the results of the retirement rate analysis and on the expectations of operational staff, Gannett Fleming recommends the use of a 65-year average service life estimate and a change in the mode of the Iowa curve from S4 to R4, resulting in a recommended Iowa 65-R4 curve.

<u>Account Grouping 000G – Turbines and Generators</u>, represents 21.2% of the hydraulic generation assets and 8.1% of the depreciable assets studied. The investment in this account relates to the turbines and generator equipment. The assets in this account were previously depreciated using the Iowa 65-R3 curve. Over the period since the last depreciation study $14.4 million of retirement activity has occurred. The average service life estimates for a Canadian peer group reviewed as part of this study indicated a range of approved average service life estimates ranging from 50 through 75 years. Based on the retirement rate analysis as presented on pages V-23 through V-25 of the Supporting Documents, Gannett Fleming recommends shortening the average service life estimate from the Iowa 65-R3 to the Iowa 60-S3, which is consistent with the historic retirement patterns and remains in the range of average service life estimates of the Canadian peer group.

<u>Account Grouping 000P – A/C Electrical Power Systems</u>, represents 6.4% of the hydraulic generation assets and 2.4% of the depreciable assets studied. The investment in this account relates to the station electric transformer and station service. The assets in this account were previously depreciated using the Iowa 50-R3 curve. Over the period since the last depreciation study, this account has witnessed over $3.7 million of retirement activity. Based on the retirement rate analysis as presented on pages V-30 through V-32 of the Supporting Documents, an extension to the average service life is recommended. Additionally, the expectations of operational staff confirm

that the Iowa 50-R3 is no longer appropriate. As such, Gannett Fleming recommends the use of the Iowa 55-R4, as shown on page V-29 of the Supporting Documents.

Thermal Accounts

Investment in thermal generation is identified by Accounts 1205B through 1215W. These thermal generation units are located in the Brandon area (two natural gas-fired units; one coal-fired unit) and on the east side of the Town of Selkirk (two natural gas-fired units).

Account Grouping – 1200B – Powerhouse, represents 7.6% of the Thermal assets and less than 0.2% of the depreciable assets studied. The thermal generation powerhouses are more typical of industrial concrete or steel buildings. As such, it is estimated that the average service life associated with powerhouse buildings related to thermal plant locations would have a shorter average service life in contrast to those estimates for the hydraulic generation sites.

The statistical analysis indicates a life of approximately 75 years. Manitoba Hydro operational staff confirm the life expectation of 75 years. Based on the retirement rate analysis as presented on pages V-53 and V-54 of the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends an extension to the Iowa curve estimates of this account from the 65-R4 to an Iowa 75-R5.

Account Grouping – 1200G – Turbines and Generators, represents 12.2% of the Thermal assets and 0.4% of the depreciable assets studied. Based on the retirement rate analysis as presented on pages V-59 through V-60 of the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends the use of the Iowa 60-S3, as shown on page V-58 of the Supporting Documents.

Account Grouping – 1200J – Steam Generators and Auxiliaries, represents 15.1% of the Thermal assets and less than 0.5% of the depreciable assets studied. The statistical analysis indicates a life of approximately 60 years. Manitoba Hydro operational staff confirm the life expectation of 60 years. Based on the retirement rate analysis as presented on pages V-64 and V-65 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends a shortening of the average service life estimate for this account from 65-R2.5 and retirement dispersion curve of this account to an Iowa 60-S2.5.

Account Grouping – 1200K – Combustion Turbine, represents 32.6% of the Thermal assets and less than 1.0% of the depreciable assets studied. The operational staff at Manitoba Hydro also confirm the life expectation of 25 years. Based on the retirement rate analysis as presented on page V-67 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends no change to the average service life estimate but a slight adjustment to the retirement dispersion pattern to an Iowa 25-R3.

Account Grouping – 1200Q – Instrumentation, Control and D/C Systems, represents 7.4% of the Thermal assets and less than 0.2% of the depreciable assets studied. The statistical analysis indicates a life of approximately 25 years. Manitoba Hydro operational staff confirm the life expectation of 25 years. Based on the retirement rate analysis as presented on pages V-72 and V-73 of the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends an extension to the Iowa curve of this account from 23-L2 to an Iowa 25-S2.

Account Grouping – 1200R – Auxiliary Station Processes, represents 16.6% of the Thermal assets and less than 0.5% of the depreciable assets studied. Based on the retirement rate analysis as presented on pages V-75 and V-76 of the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends the extension of the average service life estimate for this account to the 50-R2 from the 40-R2.5 Iowa curve which was previously used.

Diesel Accounts

Account 1300B – Buildings, represents 17.2% of the Diesel assets and less than 0.1% of the depreciable assets studied. The statistical analysis indicates a life of approximately 25 years. Manitoba Hydro operational staff confirm the life expectation of 25 years. Based on the retirement rate analysis as presented on page V-81 of the Supporting Documents and on the expectations of operational staff, Gannett Fleming recommends a shortening to the Iowa curve estimate of this account from 30-R3 to an Iowa 25-R3.

Account 1300N – Engines and Generators, represents 34.9% of the Diesel assets and less than 0.1% of the depreciable assets studied. The statistical analysis indicates a life of approximately 22 years. Manitoba Hydro operational staff confirm the life expectation of 22 years. Based on the retirement rate analysis as presented on page V-83 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends a shortening to the Iowa curve estimate of this account from 25-R2 to an Iowa 22-R2.

Account 1300T – Fuel Storage and Handling, represents 10.6% of the Diesel assets and less than 0.1% of the depreciable assets studied. The statistical analysis indicates a life of approximately 25 years. Manitoba Hydro operational staff confirm the life expectation of 25 years. Based on the retirement rate analysis as presented on page V-87 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends a shortening to the Iowa curve estimate of this account from 30-R2 to an Iowa 25-R2.

Life Span Estimates

Life expectancy of electric generation plant assets are impacted by not only physical wear and tear of the assets, but also on economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole. In circumstances where the replacement of major operating components is not economically feasible, the life of the major component can be the determining factor of the generation plant and all of the assets within the plant. As such, the depreciable remaining life of electric generation plant assets is the lesser of the physical life expectation of the asset or the period at the end of the life span of the generation plant.

The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American Regulatory jurisdictions. The basis for the determination of the life span date is usually based on one or all of the following:

- The physical life estimation of the major and vital components of the generating plant;

- The duration of operating licenses;
- Precedent and policy of the regulatory jurisdiction;
- Expiration of the supply source for which the generation plant is dependent; and
- Expiration of market demand upon which the generation plant is dependent.

In prior depreciation reviews, Manitoba Hydro has determined a life span date for most of the regulated hydraulic plants based on an overall life estimate of 140 years beyond the date of initial construction. The management and operational staff of Manitoba Hydro have reviewed this policy and determined that it remains reasonable to determine the economic life of the generation plants on the basis of this policy. The application of this policy was reviewed for its reasonableness at each of the generation plants and was modified in three circumstances as follows:

- Pointe du Bois – March 31, 2040 (134 years);
- Laurie River – March 31, 2035 (78 years); and
- Grand Rapids – March 31, 2081 (125 years).

Due to regulation changes related to coal burning plants, a terminal date has been established for Brandon Unit 5 (coal) assuming that the plant will remain available for generation until December 31, 2019.

- Brandon Unit 5 (Coal) – December 31, 2019 (50 years).

Transmission Accounts

Account 2000G – Metal Towers and Concrete Poles, represents 49.2% of the transmission assets and 3.4% of the depreciable assets studied. The company had a previously approved life estimate of 85 years for this account. The original survivor curve as shown on page V-92 of the Supporting Documents indicated a modest level of retirement activity through age 59, with an indication of increased retirement activity thereafter. The transmission towers have historically withstood environmental influences such as ice storms, severe winter conditions and corrosion. Other than the decommissioning of the towers from Pointe du Bois there are no other significant replacement plans over the next 25 to 30 years. The Canadian peer group reviewed as part of this study indicated average service life ranges from 50 to 65 years.

Interviews with company operational staff have indicated an expectation of a longer life than the industry peers. Based on the retirement rate analysis as presented on pages V-93 through V-95 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends the continued approved Iowa 85-R4 curve.

Account 2000L – Overhead Conductor and Devices, represents 35.7% of the transmission assets and 2.5% of the depreciable assets studied. The retirement pattern shows only modest retirements up until age 20 and retirements increasing at a low rate thereafter. Based on the retirement rate analysis as presented on pages V-100 through V-102 of the Supporting Documents, and on the expectations of operational staff, Gannett Fleming recommends the extension of the average service life estimate for this account from a 65-R4 Iowa curve to the Iowa 80-R4.

Substation Accounts

Account 3000B – Buildings, represents 5.6% of the substation assets and 1.2% of the depreciable assets studied. The retirement pattern as shown on pages V-106 and V-107 of the Support Documents shows modest retirements at all ages throughout the accounts life. Gannett Fleming recommends no change to the Iowa curve estimate and curve fit to this account of an Iowa 65-R4.

Account 3000F – Roads, Steel Structures and Civil Site Works, represents 10.1% of the substation assets and 2.1% of the depreciable assets studied. Comparable utilities within the electric industry have lives ranging from 50 to 57 years. The retirement pattern as shown on pages V-109 through V-111 of the Supporting Documents shows modest retirements early in this account's life and increasing thereafter. Based on the retirement rate analysis, and on the expectations of operational staff, Gannett Fleming recommends the continued use of the Iowa 50-R4 curve.

Account 3100R – Power Transformers, represents 11.6% of the substation assets and 2.4% of the depreciable assets studied. The retirement pattern shows modest retirements starting at an early age and continuing at a high rate through age

39. This account has undergone a significant amount of retirement activity since the last depreciation study with approximately $5.7 million of retirements occurring. With this large level of retirements, this account has now incurred over $48.7 million of retirements (or over 12% of all plant installed), which provides a statistically relevant base to use in the determination of the average service life estimates. As such, retirement rate analysis as provided on pages V-116 and V-117 of the Supporting Documents produced a fit of the Iowa 50-R1.5 which provides a good indication of the average service life.

The operational staff have not identified any problems with Manitoba Hydro's transformers. Manitoba Hydro has standard maintenance practices that extend the lives of the transformers for as long of a period as possible. Additionally, newer transformers are expected to have shorter lives than the older units, as the new units are being manufactured to tighter capacity tolerances. The typical industry lives range from 40 to 55 years. Based on the retirement rate analysis, and on the expectations of operational staff, Gannett Fleming recommends an Iowa 50-R1.5 curve.

Account 3100T – Interrupting Equipment, represents 7.1% of the substation assets and 1.5% of the depreciable assets studied. The retirement pattern as shown at page V-122 through V-124 of the Supporting Documents shows retirements starting early in the account's life and continuing through to age 62. Based on the retirement rate analysis Gannett Fleming recommends an extension to the Iowa curve estimate of this account from the Iowa 45-R2 to an Iowa 50-R2.5.

Account 3100U – Other Station Equipment, represents 18.6% of the substation assets and 3.9% of the depreciable assets studied. The retirement pattern is shown at pages V-126 through V-128 of the Supporting Documents. Based on the retirement rate analysis, and on the expectations of operational staff, Gannett Fleming recommends an Iowa 45-R3 curve. This is a slight extension of the Iowa curve estimate for this account from a 43-R2 to the Iowa 45-R3.

Account 3100V – Electronic Equipment and Batteries, represents 7.5% of the substation assets and 1.6% of the depreciable assets studied. The retirement pattern as shown on pages V-130 and V-131 of the Supporting Documents indicates that a life extension from the currently approved Iowa 20-R2 is required. Gannett Fleming recommends the extension of the average service life estimate for this account from a 20-R2 Iowa curve to the Iowa 25-R2.

Account 3200P – HVDC Converter Equipment, represents 14.6% of the substation assets and 3.1% of the depreciable assets studied. The retirement pattern as shown on pages V-136 and V-137 of the Supporting Documents shows modest retirements starting about year nine and slowly increasing with large retirements thereafter through age 35. This account has undergone a significant amount of retirement activity since the last depreciation study with over $22.4 million of retirements occurring. With this large level of retirements, this account has now incurred over $87.4 million of retirements (or over 17% of all plant installed), which provides a statistically relevant base to use in the determination of the average service life estimates. As such, the average service life recommendation was based primarily on the best fit analysis which indicated the Iowa 30-S4 curve. This life indication was confirmed as reasonable by the operations staff, and is therefore recommended by Gannett Fleming in this study.

Account 3200S – HDVC Serialized Equipment, represents 7.2% of the substation assets and 1.5% of the depreciable assets studied. The retirement pattern as shown at pages V-139 and V-140 of the Supporting Documents shows significant retirement activity starting at age 18 and continuing through age 38. Based on the retirement rate analysis Gannett Fleming recommends an extension to the Iowa curve estimate of this account from the Iowa 25-R2 to an Iowa 30-R5.

Account 3200U – HDVC Accessory Station Equipment, represents 5.7% of the substation assets and 1.2% of the depreciable assets studied. This account has undergone a significant amount of retirement activity since the last depreciation study with approximately $3.1 million of retirements occurring. With this large level of retirements, this account has now incurred approximately $20.3 million of retirements (or over 11% of all plant installed), which provides a statistically relevant base to use in the determination of the average service life estimates. As such, the retirement rate analysis produced a fit of the Iowa 36-R3 which provides a good indication of the average service life. As such Gannett Fleming recommends a small decrease to the Iowa curve estimate of this account from the Iowa 37-R4 to this account to an Iowa 36-R3.

Distribution Accounts

Account 4000J – Poles and Fixtures, represents 23.5% of the distribution assets and 4.7% of the depreciable assets studied. Typical industry lives for wood poles range from 25 to 55 years. The retirement rate analysis as shown on pages V-155 through V-157 of the Supporting Documents has indicated a preliminary average service life estimate of the Iowa 55-R1.5. However, it was the view of the operations staff that the life of poles within the Manitoba Hydro system should be at least 65 years based on a recent internally developed study of the poles in service.

Based on all factors, Gannett Fleming recommends an Iowa 65-S0.5 curve, which provides a reasonable fit to the actual retirement experience and conforms to the view of the Manitoba Hydro operational staff.

Account 4000L – Overhead Conductor and Devices, represents 24.9% of the distribution assets and 5.0% of the depreciable assets studied. The retirement rate analysis as shown on pages V-159 and V-160 have indicated a high rate of early retirements leading to a low-mode Iowa curve. The currently approved life estimate for this account is the Iowa 60-R2 which is consistent with the operational staff indications that they are seeing no major issues with conductors and they would expect lives of conductor to be approximately 60 years. Based on all factors, Gannett Fleming recommends a reduction of the mode of the curve to an Iowa 60-R1.5, which maintains the average service life estimate for the previous depreciation study but adjusts to a lower mode to recognize the increased level of early retirement experience.

Account 4000N – Underground Cable and Devices - Primary, represents 13.0% of the distribution assets and 2.6% of the depreciable assets studied. Operational staff indicated there are no major issues with newer underground cable installed within the last 25 years. Cable previously installed, however, is experiencing retirements at about 45 years. Based on the retirement rate analysis as shown on pages V-165 and V-166 of the Supporting Documents and on more recent expectations of operational staff, Gannett Fleming recommends a small adjustment of the approved Iowa 60-R4 curve to an Iowa 60-R3 curve.

Account 4000P – Underground Cable and Devices - Secondary, represents 8.7% of the distribution assets and 1.8% of the depreciable assets studied. The newer underground cable is about 28 years old and is showing no major issues according to Manitoba Hydro's operational staff. Underground cable installed prior to this vintage is starting to retire at about 45 years. Based on the retirement rate analysis as shown on pages V-168 and V-169 of the Supporting Documents and the expectations of operational staff along with industry comparables, Gannett Fleming recommends an Iowa 44-S3 curve, which represents a small adjustment to the currently approved Iowa 45-R4.

Account 4000Q – Serialized Equipment - Overhead, represents 7.6% of the distribution assets and 1.5% of the depreciable assets studied. The investment in this account primarily relates to pole top transformers. Interviews with operational staff indicated the company intends to continue to refurbish and reuse transformers. Based on the retirement rate analysis as shown on pages V-171 through V-173 of the Supporting Documents and the expectations of operational staff along with industry comparables, Gannett Fleming recommends an extension from the currently approved Iowa 35-R3 curve to the Iowa 45-R3 curve.

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

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CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Service Life (ASL) and Equal Life Group (ELG).

In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

The table on the following page presents an illustration of the calculation of equal life group depreciation in a mass property account using the Iowa 15-L3 survivor curve, 0 percent net salvage and a December 31, 2013 calculation date. In the table, each equal life group is defined by the age interval shown in columns 1 and 2. These are the ages at which the first and last retirement of each group occurs, and the group's equal life, shown in column 3, is the midpoint of the interval. For purposes of the calculation, each vintage is divided into equal life groups arranged so that the midpoint of each one-year age interval coincides with the calculation date, e.g., December 31 in this case. This enables the calculation of annual accruals for a twelve-month period centered on the date of calculation.

The retirement during the age interval, shown in column 4, is the size of each equal life group and is derived from the Iowa 15-L3 survivor curve and 0 percent net salvage. It is the difference between the percents surviving at the beginning and end of the age interval. Each equal life group's annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3).

Columns 7 through 10 show the derivation of the annual and accrued factors for each vintage based on the information developed in the first five columns. The year installed is shown in column 6. For all vintages other than 2013, the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For example, the figure 7.54580659712 for 2012 equals one-half of 0.00417333333 plus all of the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the equal life group for that interval has reached the year during which it is expected to be retired.

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE

INPUT PARAMETERS:
CALCULATION DATE.. 12-31-2013
SURVIVOR CURVE.... 15-L3

AGE INTERVAL BEG (1)	END (2)	LIFE (3)	RETIREMENTS DURING INTERVAL (4)	GROUP ANNUAL ACCRUAL (5)=(4)/(3)	YEAR INST (6)	SUMMATION OF ANNUAL ACCRUALS (7)	AVERAGE PERCENT SURVIVING (8)	ANNUAL FACTOR (9)	ACCRUED FACTOR (10)
0.000	1.000	0.500	0.00000	0.00000000000	2013	7.54789326379	100.000000	0.0755	0.0378
1.000	2.000	1.500	0.00626	0.00417333333	2012	7.54580659712	99.996871	0.0755	0.1133
2.000	3.000	2.500	0.07371	0.02948400000	2011	7.52897793046	99.956886	0.0753	0.1883
3.000	4.000	3.500	0.24938	0.07125142857	2010	7.47861021617	99.795341	0.0749	0.2622
4.000	5.000	4.500	0.53052	0.11789333333	2009	7.38403783522	99.405391	0.0743	0.3344
5.000	6.000	5.500	0.90946	0.16535636364	2008	7.24241298674	98.685400	0.0734	0.4037
6.000	7.000	6.500	1.42549	0.21930615385	2007	7.05008172799	97.517924	0.0723	0.4700
7.000	8.000	7.500	2.20064	0.29341866667	2006	6.79371931773	95.704861	0.0710	0.5325
8.000	9.000	8.500	3.39884	0.39986352941	2005	6.44707821969	92.905122	0.0694	0.5899
9.000	10.000	9.500	5.04554	0.53110947368	2004	5.98159171815	88.682933	0.0674	0.6403
10.000	11.000	10.500	6.85105	0.65248095238	2003	5.38979650512	82.734638	0.0651	0.6836
11.000	12.000	11.500	8.38308	0.72896347826	2002	4.69907428980	75.117571	0.0626	0.7199
12.000	13.000	12.500	9.24339	0.73947120000	2001	3.96485695067	66.304334	0.0598	0.7475
13.000	14.000	13.500	9.26729	0.68646592593	2000	3.25188838770	57.048992	0.0570	0.7695
14.000	15.000	14.500	8.60115	0.59318275862	1999	2.61206404543	48.114774	0.0543	0.7874
15.000	16.000	15.500	7.52494	0.48548000000	1998	2.07273266612	40.051733	0.0518	0.8029
16.000	17.000	16.500	6.36246	0.38560363636	1997	1.63719084794	33.108032	0.0494	0.8151
17.000	18.000	17.500	5.31546	0.30374057143	1996	1.29251874404	27.269070	0.0474	0.8295
18.000	19.000	18.500	4.45790	0.24096756757	1995	1.02016467454	22.382391	0.0456	0.8436
19.000	20.000	19.500	3.79278	0.19450153846	1994	0.80243012153	18.257053	0.0440	0.8580
20.000	21.000	20.500	3.26252	0.15914731707	1993	0.62560569376	14.729403	0.0425	0.8713
21.000	22.000	21.500	2.80655	0.13053720930	1992	0.48076343058	11.694867	0.0411	0.8837
22.000	23.000	22.500	2.39730	0.10654666667	1991	0.36222149259	9.092942	0.0398	0.8955
23.000	24.000	23.500	2.01248	0.08563744681	1990	0.26612943585	6.888050	0.0386	0.9071
24.000	25.000	24.500	1.64563	0.06716857143	1989	0.18972642673	5.058997	0.0375	0.9188
25.000	26.000	25.500	1.30683	0.05124823529	1988	0.13051802337	3.582767	0.0364	0.9282
26.000	27.000	26.500	1.00069	0.03776188679	1987	0.08601296233	2.429005	0.0354	0.9381
27.000	28.000	27.500	0.73137	0.02659527273	1986	0.05383438257	1.562976	0.0344	0.9460
28.000	29.000	28.500	0.50766	0.01781263158	1985	0.03163043042	0.943461	0.0335	0.9548
29.000	30.000	29.500	0.32937	0.01116508475	1984	0.01714157225	0.524945	0.0327	0.9647
30.000	31.000	30.500	0.19482	0.00638754098	1983	0.00836525939	0.262852	0.0318	0.9699
31.000	32.000	31.500	0.10249	0.00325365079	1982	0.00354466350	0.114197	0.0310	0.9765
32.000	33.000	32.500	0.04513	0.00138861538	1981	0.00122353042	0.040385	0.0303	0.9848
33.000	34.000	33.500	0.01480	0.00044179104	1980	0.00030832721	0.010422	0.0296	0.9916
34.000	35.000	34.500	0.00287	0.00008318841	1979	0.00004583748	0.001588	0.0289	0.9971
35.000	35.700	35.350	0.00015	0.00000424328	1978	0.00000148515	0.000053	0.0280	1.0000
TOTAL			100.00000						

The summation of annual accruals (column 7) for installations during 2012 is calculated on the basis of an in-service date at the midpoint of the year, i.e., June 30. Inasmuch as the overall calculation is centered on December 31, 2013, the first figure in column 7, for vintage 2014, equals all of the group annual accrual for the first equal life group plus the accruals for all of the subsequent equal life groups.

The average percent surviving derived from the Iowa 15-L3 survivor curve and 0 percent net salvage, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8). The accrued factor, shown in column 10, equals the annual factor multiplied by the age of the group at December 31, 2013.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

For the purpose of calculating annual amortization amounts as of March 31, 2014, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable plant in service. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD, YEARS
Group 000C	Hydraulic Generation - Powerhouse Renovations	40
Group 000L	Hydraulic Generation – License Renewal	50
Group 000W	Hydraulic Generation - Support Building Renovations	20
Group 000Z	Hydraulic Generation – Community Development Costs	78-90
1200C	Thermal Generation – Powerhouse Renovations	40
1200L	Thermal Generation - License Renewal	50
1200W	Thermal Generation – Support Building Renovations	20
1300C	Diesel Generation – Building Renovations	15
1300M	Diesel Generation – Engine and Generators – Overhauls	4
2000K	Transmission – Ground Line Treatment	10
2000Z	Transmission – Community Development Costs	79
3000C	Substations – Building Renovations	20
3200N	Substations – Synchronous Condenser Overhauls	15
4000K	Distribution – Ground Line Treatment	12
4000V	Distribution - Electronic Equipment	10
4900W	Meters - Metering Exchanges	15
5000C	Communication – Building Renovations	20
5000K	Communication – Operational IT Equipment	5
5000M	Communication – Mobile Radio, Telephone and Video Conferencing	8
5000N	Communication – Operational Data Network	8
8000C	General Plant – Building Renovations	20
8000F	General Plant – Leasehold Improvements – Sony Place	10
9000H	General Plant – Tools, Shop and Garage Equipment	15
9000K	General Plant – Computer Equipment	5
9000L	General Plant – Office Furniture and Equipment	20
9000M	General Plant – Hot Water Tanks	6
A100A	Easements	75
A200H	Computer Development – Small Systems	10
A200J	Computer Software – General	5
A200K	Computer Software – Communication/Operational	5

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

$$\text{Composite Remaining Life} = \frac{\sum\left(\frac{\text{Book Cost}}{\text{Life}} \text{ x Remaining Life}\right)}{\sum \frac{\text{Book Cost}}{\text{Life}}}.$$

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining Life} = \frac{\sum \text{Whole Life Future Accruals}}{\sum \text{Whole Life Annual Accruals}}$$

or

$$\text{Composite Remaining Life} = \frac{\sum \text{Book Cost - Calc. Reserve}}{\sum \text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

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QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates used by other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on V-2 of the Supporting Documents.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves is followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets of Manitoba Hydro as of March 31, 2014 are presented in account sequence starting on page VI-2 of the Supporting Documents. The tables of the calculated annual depreciation applicable to depreciable assets of Wuskwatim Power Limited Partnership as of March 31, 2014 are presented in account sequence starting on page VI-323 of the Supporting Documents. Additionally, the tables indicate the estimated average survivor curves used in the calculations, and set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	GENERATION									
	HYDRAULIC GENERATION									
	GREAT FALLS									
1105A	DAMS, DYKES AND WEIRS	2063	125-R4	0	17,345,473	220,697	1.27	(27,100)	193,597	1.12
1105B	POWERHOUSE	2063	125-R4	0	7,990,993	100,417	1.26	(14,580)	85,837	1.07
1105C	POWERHOUSE RENOVATIONS	2063	40-SQ	0	47,039	1,176	2.50	(44)	1,132	2.41
1105D	SPILLWAY	2063	80-R3	0	9,676,327	142,204	1.47	(11,388)	130,816	1.35
1105E	WATER CONTROL SYSTEMS	2063	65-R4	0	24,245,253	416,245	1.72	(88,462)	327,783	1.35
1105F	ROADS AND SITE IMPROVEMENTS	2063	50-R3	0	935,986	22,637	2.42	39	22,676	2.42
1105G	TURBINES AND GENERATORS	2063	60-S3	0	33,818,312	647,992	1.92	39,027	687,019	2.03
1105H	GOVERNORS AND EXCITATION SYSTEM	2063	50-R4	0	1,154,724	24,660	2.14	(819)	23,841	2.06
1105L	LICENCE RENEWAL	2063	50-SQ	0						2.04 *
1105P	A/C ELECTRICAL POWER SYSTEMS	2063	55-R4	0	9,493,088	178,427	1.88	(20,168)	158,259	1.67
1105Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2063	25-S2	0	19,506,209	814,380	4.17	(74,717)	739,663	3.79
1105R	AUXILIARY STATION PROCESSES	2063	50-R2	0	10,221,178	239,221	2.34	(24,148)	215,073	2.10
1105X	SUPPORT BUILDINGS	2063	65-S3	0	1,495,253	23,552	1.58	(3,230)	20,322	1.36
1105W	SUPPORT BUILDING RENOVATIONS	2063	20-SQ	0	18,859	943	5.00		943	5.00 **
	TOTAL GREAT FALLS				**135,948,694**	**2,832,551**	**2.08**	**(225,590)**	**2,606,961**	**1.92**
	POINTE DU BOIS									
1110A	DAMS, DYKES AND WEIRS	2040	125-R4	0	20,718,888	704,154	3.40	(144,282)	559,873	2.70
1110B	POWERHOUSE	2040	125-R4	0	6,054,784	193,943	3.20	(39,792)	154,151	2.55
1110C	POWERHOUSE RENOVATIONS	2040	40-SQ	0	1,897,782	72,083	3.80	(1,714)	70,370	3.71
1110D	SPILLWAY - ORIGINAL	2015	80-R3	0	7,797,851	4,393,673	56.34	1,327,437	5,721,110	73.37
1110E	WATER CONTROL SYSTEMS	2040	65-R4	0	4,466,812	133,247	2.98	(55,974)	77,273	1.73
1110F	ROADS AND SITE IMPROVEMENTS	2040	50-R3	0	1,055,707	40,466	3.83	(345)	40,121	3.80
1110G	TURBINES AND GENERATORS	2040	60-S3	0	31,899,060	1,036,836	3.25	(256,998)	779,838	2.44
1110H	GOVERNORS AND EXCITATION SYSTEM	2040	50-R4	0						3.68 *
1110L	LICENCE RENEWAL	2040	50-SQ	0						3.85 *
1110P	A/C ELECTRICAL POWER SYSTEMS	2040	55-R4	0	7,759,986	264,381	3.41	(48,663)	215,718	2.78
1110Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2040	25-S2	0	1,037,485	48,861	4.71	(4,685)	44,176	4.26
1110R	AUXILIARY STATION PROCESSES	2040	50-R2	0	5,357,425	206,590	3.86	(14,293)	192,297	3.59
1110X	SUPPORT BUILDINGS	2040	65-S3	0	882,202	28,086	3.18	(5,245)	22,841	2.59
1110W	SUPPORT BUILDING RENOVATIONS	2040	20-SQ	0	347,164	17,358	5.00	(4,017)	13,341	3.84
	TOTAL POINTE DU BOIS				**89,275,145**	**7,139,678**	**8.00**	**751,430**	**7,891,108**	**8.84**
	POINTE DU BOIS - NEW									
1111A	DAMS, DYKES AND WEIRS		125-R4	0						0.85 *
1111D	SPILLWAY		80-R3	0						1.49 *
1111E	WATER CONTROL SYSTEMS		65-R4	0						1.64 *
1111F	ROADS AND SITE IMPROVEMENTS		50-R3	0						2.36 *
1111P	A/C ELECTRICAL POWER SYSTEMS		55-R4	0						1.94 *
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	0						4.54 *
1111R	AUXILIARY STATION PROCESSES		50-R2	0						3.01 *
1111X	SUPPORT BUILDINGS		65-S3	0						1.65 *
1111W	SUPPORT BUILDING RENOVATIONS		20-SQ	0						5.00 *
	TOTAL POINTE DU BOIS - NEW				**0**	**0**		**0**	**0**	
	SEVEN SISTERS									
1115A	DAMS, DYKES AND WEIRS	2072	125-R4	0	31,926,879	364,039	1.14	(77,667)	286,372	0.90
1115B	POWERHOUSE	2072	125-R4	0	13,653,945	143,708	1.05	(42,858)	100,850	0.74
1115C	POWERHOUSE RENOVATIONS	2072	40-SQ	0	578,473	14,462	2.50	(543)	13,919	2.41
1115D	SPILLWAY	2072	80-R3	0	2,940,065	39,166	1.33	(4,779)	34,387	1.17
1115E	WATER CONTROL SYSTEMS	2072	65-R4	0	4,520,291	70,491	1.56	(24,166)	46,325	1.02
1115F	ROADS AND SITE IMPROVEMENTS	2072	50-R3	0	205,641	3,727	1.81	(1,044)	2,683	1.30
1115G	TURBINES AND GENERATORS	2072	60-S3	0	54,449,323	986,438	1.81	(64,103)	922,335	1.69
1115H	GOVERNORS AND EXCITATION SYSTEM	2072	50-R4	0	290,552	6,191	2.13	(44)	6,148	2.12
1115L	LICENCE RENEWAL	2072	50-SQ	0						2.00 *
1115P	A/C ELECTRICAL POWER SYSTEMS	2072	55-R4	0	11,924,230	223,527	1.87	(37,834)	185,693	1.56
1115Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2072	25-S2	0	4,960,007	196,592	3.96	(26,159)	170,433	3.44
1115R	AUXILIARY STATION PROCESSES	2072	50-R2	0	8,512,853	197,047	2.31	(24,490)	172,557	2.03
1115X	SUPPORT BUILDINGS	2072	65-S3	0	608,294	10,491	1.72	(1,219)	9,272	1.52
1115W	SUPPORT BUILDING RENOVATIONS	2072	20-SQ	0						5.00 *
	TOTAL SEVEN SISTERS				**134,570,553**	**2,255,879**	**1.68**	**(304,905)**	**1,950,974**	**1.45**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK (1)	LIFE SPAN DATE	SURVIVOR CURVE (2)	NET SALVAGE (3)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (4)	CALCULATED ANNUAL ACCRUAL AMOUNT (5)	CALCULATED ANNUAL ACCRUAL RATE (%) (6)=(5)/(4)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RELATED TO LIFE RATE (%) (9)=(8)/(4)	
	SLAVE FALLS										
1120A	DAMS, DYKES AND WEIRS	2072	125-R4	0	954,684	14,948	1.57	(255)	14,693	1.54	
1120B	POWERHOUSE	2072	125-R4	0	45,692,194	672,763	1.47	(20,510)	652,253	1.43	
1120C	POWERHOUSE RENOVATIONS	2072	40-SQ	0						2.50	*
1120D	SPILLWAY	2072	80-R3	0	1,241,273	21,831	1.76	(226)	21,605	1.74	
1120E	WATER CONTROL SYSTEMS	2072	65-R4	0	318,933	5,549	1.74	(281)	5,269	1.65	
1120F	ROADS AND SITE IMPROVEMENTS	2072	50-R3	0	37,971,797	882,232	2.32	14,122	896,354	2.36	
1120G	TURBINES AND GENERATORS	2072	60-S3	0	12,246,529	224,685	1.83	(3,206)	221,479	1.81	
1120H	GOVERNORS AND EXCITATION SYSTEM	2072	50-R4	0	336,652	7,204	2.14	(63)	7,141	2.12	
1120L	LICENCE RENEWAL	2072	50-SQ	0						2.00	*
1120P	A/C ELECTRICAL POWER SYSTEMS	2072	55-R4	0	21,631,850	421,951	1.95	(9,787)	412,164	1.91	
1120Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2072	25-S2	0	4,446,295	201,003	4.52	1,856	202,859	4.56	
1120R	AUXILIARY STATION PROCESSES	2072	50-R2	0	5,288,154	139,825	2.64	3,153	142,978	2.70	
1120X	SUPPORT BUILDINGS	2072	65-S3	0	3,306,577	57,211	1.73	5,434	62,645	1.89	
1120W	SUPPORT BUILDING RENOVATIONS	2072	20-SQ	0						5.00	*
	TOTAL SLAVE FALLS				**133,434,938**	**2,649,202**	**1.99**	**(9,764)**	**2,639,438**	**1.98**	
	PINE FALLS										
1125A	DAMS, DYKES AND WEIRS	2092	125-R4	0	18,301,512	211,283	1.15	(7,150)	204,133	1.12	
1125B	POWERHOUSE	2092	125-R4	0	10,060,843	87,916	0.87	(16,243)	71,673	0.71	
1125C	POWERHOUSE RENOVATIONS	2092	40-SQ	0	121,809	3,045	2.50	(113)	2,932	2.41	
1125D	SPILLWAY	2092	80-R3	0	93,376	1,406	1.51	(12)	1,394	1.49	
1125E	WATER CONTROL SYSTEMS	2092	65-R4	0	3,660,833	56,041	1.53	(17,069)	38,972	1.06	
1125F	ROADS AND SITE IMPROVEMENTS	2092	50-R3	0	1,180,058	18,950	1.61		18,950	1.61	****
1125G	TURBINES AND GENERATORS	2092	60-S3	0	9,318,154	150,312	1.61	(22,361)	127,951	1.37	
1125H	GOVERNORS AND EXCITATION SYSTEM	2092	50-R4	0						2.13	*
1125L	LICENCE RENEWAL	2092	50-SQ	0						2.00	*
1125P	A/C ELECTRICAL POWER SYSTEMS	2092	55-R4	0	5,096,978	92,115	1.81	(11,342)	80,773	1.58	
1125Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2092	25-S2	0	3,881,573	164,103	4.23	(7,396)	156,707	4.04	
1125R	AUXILIARY STATION PROCESSES	2092	50-R2	0	3,976,778	84,927	2.14	(13,140)	71,787	1.81	
1125X	SUPPORT BUILDINGS	2092	65-S3	0	336,412	5,551	1.65	(296)	5,255	1.56	
1125W	SUPPORT BUILDING RENOVATIONS	2092	20-SQ	0						5.00	*
1125Z	COMMUNITY DEVELOPMENT COSTS ***	2092	78-SQ	0	26,531,770	339,607	1.28		339,607	1.28	**
	TOTAL PINE FALLS				**82,560,097**	**1,215,256**	**1.47**	**(95,123)**	**1,120,133**	**1.36**	
	MCARTHUR FALLS										
1130A	DAMS, DYKES AND WEIRS	2095	125-R4	0	6,837,356	72,294	1.06	(3,729)	68,566	1.00	
1130B	POWERHOUSE	2095	125-R4	0	9,358,105	80,201	0.86	(13,060)	67,141	0.72	
1130C	POWERHOUSE RENOVATIONS	2095	40-SQ	0	405,461	10,137	2.50	(377)	9,760	2.41	
1130D	SPILLWAY	2095	80-R3	0	2,417,504	28,751	1.19	(5,359)	23,392	0.97	
1130E	WATER CONTROL SYSTEMS	2095	65-R4	0	11,703,203	187,593	1.60	(41,553)	146,040	1.25	
1130F	ROADS AND SITE IMPROVEMENTS	2095	50-R3	0	235,262	4,656	1.98	(625)	4,031	1.71	
1130G	TURBINES AND GENERATORS	2095	60-S3	0	5,379,618	77,690	1.44	(27,218)	50,472	0.94	
1130H	GOVERNORS AND EXCITATION SYSTEM	2095	50-R4	0	119,315	2,500	2.10	(190)	2,310	1.94	
1130L	LICENCE RENEWAL	2095	50-SQ	0						2.00	*
1130P	A/C ELECTRICAL POWER SYSTEMS	2095	55-R4	0	2,521,761	43,075	1.71	(9,746)	33,329	1.32	
1130Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2095	25-S2	0	1,275,876	42,733	3.35	(7,783)	34,950	2.74	
1130R	AUXILIARY STATION PROCESSES	2095	50-R2	0	3,616,031	77,458	2.14	(10,590)	66,868	1.85	
1130X	SUPPORT BUILDINGS	2095	65-S3	0						1.67	*
1130W	SUPPORT BUILDING RENOVATIONS	2095	20-SQ	0						5.00	*
	TOTAL MCARTHUR FALLS				**43,869,489**	**627,088**	**1.43**	**(120,231)**	**506,857**	**1.16**	

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TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	KELSEY									
1135A	DAMS, DYKES AND WEIRS	2101	125-R4	0	9,296,418	90,411	0.97	5,765	96,176	1.03
1135B	POWERHOUSE	2101	125-R4	0	71,294,313	742,942	1.04	29,628	772,570	1.08
1135C	POWERHOUSE RENOVATIONS	2101	40-SQ	0						2.50 *
1135D	SPILLWAY	2101	80-R3	0	7,196,926	91,951	1.28	21,592	113,543	1.58
1135E	WATER CONTROL SYSTEMS	2101	65-R4	0	35,342,564	572,076	1.62	(1,880)	570,196	1.61
1135F	ROADS AND SITE IMPROVEMENTS	2101	50-R3	0	12,310,412	257,602	2.09	25,875	283,477	2.30
1135G	TURBINES AND GENERATORS	2101	60-S3	0	146,383,857	2,613,973	1.79	91,265	2,705,238	1.85
1135H	GOVERNORS AND EXCITATION SYSTEM	2101	50-R4	0	6,948,606	147,689	2.13	3,204	150,893	2.17
1135L	LICENCE RENEWAL	2101	50-SQ	0						2.00 *
1135P	A/C ELECTRICAL POWER SYSTEMS	2101	55-R4	0	40,494,515	779,913	1.93	42,291	822,204	2.03
1135Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2101	25-S2	0	13,650,816	589,276	4.32	40,922	630,198	4.62
1135R	AUXILIARY STATION PROCESSES	2101	50-R2	0	9,929,302	221,517	2.23	7,836	229,353	2.31
1135X	SUPPORT BUILDINGS	2101	65-S3	0	13,448,502	221,470	1.65	10,817	232,287	1.73
1135W	SUPPORT BUILDING RENOVATIONS	2101	20-SQ	0	1,598,817	79,941	5.00	(9,033)	70,908	4.44
	TOTAL KELSEY				**367,895,048**	**6,408,761**	**1.74**	**268,281**	**6,677,042**	**1.81**
	GRAND RAPIDS									
1140A	DAMS, DYKES AND WEIRS	2091	125-R4	0	56,613,946	556,038	0.98	(45,671)	510,367	0.90
1140B	POWERHOUSE	2091	125-R4	0	24,506,522	223,446	0.91	(25,157)	198,289	0.81
1140C	POWERHOUSE RENOVATIONS	2091	40-SQ	0	31,603	790	2.50	(68)	722	2.28
1140D	SPILLWAY	2091	80-R3	0	5,451,760	68,277	1.25	(5,771)	62,506	1.15
1140E	WATER CONTROL SYSTEMS	2091	65-R4	0	15,982,492	244,058	1.53	(85,991)	158,067	0.99
1140F	ROADS AND SITE IMPROVEMENTS	2091	50-R3	0	2,581,475	45,629	1.77	(14,325)	31,304	1.21
1140G	TURBINES AND GENERATORS	2091	60-S3	0	113,213,625	2,003,975	1.77	(36,364)	1,967,611	1.74
1140H	GOVERNORS AND EXCITATION SYSTEM	2091	50-R4	0	1,922,915	40,941	2.13	105	41,046	2.13
1140L	LICENCE RENEWAL	2091	50-SQ	0	83,122,204	1,662,444	2.00		1,662,444	2.00 **
1140P	A/C ELECTRICAL POWER SYSTEMS	2091	55-R4	0	8,240,545	153,036	1.86	(16,600)	136,436	1.66
1140Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2091	25-S2	0	4,690,245	149,256	3.18	(32,297)	116,959	2.49
1140R	AUXILIARY STATION PROCESSES	2091	50-R2	0	12,334,108	297,403	2.41	(14,841)	282,562	2.29
1140X	SUPPORT BUILDINGS	2091	65-S3	0	8,700,819	141,567	1.63	(2,358)	139,209	1.60
1140W	SUPPORT BUILDING RENOVATIONS	2091	20-SQ	0	6,828,234	341,412	5.00		341,412	5.00 **
1140Z	COMMUNITY DEVELOPMENT COSTS ***	2091	79-SQ	0	135,205,073	1,717,104	1.27	(86,566)	1,630,538	1.21
	TOTAL GRAND RAPIDS				**479,425,566**	**7,645,376**	**1.59**	**(365,903)**	**7,279,473**	**1.52**
	KETTLE									
1145A	DAMS, DYKES AND WEIRS	2111	125-R4	0	45,280,663	390,119	0.86	(35,109)	355,010	0.78
1145B	POWERHOUSE	2111	125-R4	0	146,313,138	1,263,698	0.86	(112,336)	1,151,363	0.79
1145C	POWERHOUSE RENOVATIONS	2111	40-SQ	0						2.50 *
1145D	SPILLWAY	2111	80-R3	0	25,406,960	322,668	1.27	(27,076)	295,592	1.16
1145E	WATER CONTROL SYSTEMS	2111	65-R4	0	19,033,816	295,080	1.55	(126,323)	168,757	0.89
1145F	ROADS AND SITE IMPROVEMENTS	2111	50-R3	0	556,723	12,776	2.29	66	12,842	2.31
1145G	TURBINES AND GENERATORS	2111	60-S3	0	99,163,384	1,693,671	1.71	23,758	1,717,429	1.73
1145H	GOVERNORS AND EXCITATION SYSTEM	2111	50-R4	0	6,930,643	140,460	2.03	(7,696)	132,764	1.92
1145L	LICENCE RENEWAL	2111	50-SQ	0						2.00 *
1145P	A/C ELECTRICAL POWER SYSTEMS	2111	55-R4	0	38,779,613	745,736	1.92	12,798	758,534	1.96
1145Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2111	25-S2	0	16,263,031	588,362	3.62	(40,007)	548,356	3.37
1145R	AUXILIARY STATION PROCESSES	2111	50-R2	0	19,306,615	415,150	2.15	(55,528)	359,623	1.86
1145X	SUPPORT BUILDINGS	2111	65-S3	0	2,456,258	40,432	1.65	1,221	41,653	1.70
1145W	SUPPORT BUILDING RENOVATIONS	2111	20-SQ	0						5.00 *
	TOTAL KETTLE				**419,490,845**	**5,908,152**	**1.41**	**(366,231)**	**5,541,921**	**1.32**

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TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK (1)	LIFE SPAN DATE	SURVIVOR CURVE (2)	NET SALVAGE (3)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (4)	CALCULATED ANNUAL ACCRUAL AMOUNT (5)	CALCULATED ANNUAL ACCRUAL RATE (%) (6)=(5)/(4)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RELATED TO LIFE RATE (%) (9)=(8)/(4)
	LAURIE RIVER									
1150A	DAMS, DYKES AND WEIRS	2035	125-R4	0	355,538	7,686	2.16	1,922	9,608	2.70
1150B	POWERHOUSE	2035	125-R4	0	7,664,146	243,988	3.18	16,589	260,577	3.40
1150C	POWERHOUSE RENOVATIONS	2035	40-SQ	0						4.76 *
1150D	SPILLWAY	2035	80-R3	0	870,000	22,185	2.55	3,561	25,746	2.96
1150E	WATER CONTROL SYSTEMS	2035	65-R4	0	458,033	12,046	2.63	1,825	13,871	3.03
1150F	ROADS AND SITE IMPROVEMENTS	2035	50-R3	0	1,441,914	39,181	2.72	7,352	46,533	3.23
1150G	TURBINES AND GENERATORS	2035	60-S3	0	4,603,136	160,625	3.49	6,099	166,724	3.62
1150H	GOVERNORS AND EXCITATION SYSTEM	2035	50-R4	0	882,653	33,131	3.75	472	33,603	3.81
1150L	LICENCE RENEWAL	2035	50-SQ	0						4.76 *
1150P	A/C ELECTRICAL POWER SYSTEMS	2035	55-R4	0	1,441,945	40,426	2.80	4,948	45,374	3.15
1150Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2035	25-S2	0	1,220,047	43,552	3.57	19,240	62,792	5.15
1150R	AUXILIARY STATION PROCESSES	2035	50-R2	0	308,504	8,790	2.85	1,435	10,225	3.31
1150X	SUPPORT BUILDINGS	2035	65-S3	0	355,919	8,649	2.43	1,582	10,231	2.87
1150W	SUPPORT BUILDING RENOVATIONS	2035	20-SQ	0						5.00 *
	TOTAL LAURIE RIVER				**19,601,835**	**620,259**	**3.16**	**65,025**	**685,284**	**3.50**
	JENPEG									
1155A	DAMS, DYKES AND WEIRS	2118	125-R4	0	16,438,690	147,193	0.90	(9,694)	137,499	0.84
1155B	POWERHOUSE	2118	125-R4	0	76,905,294	663,517	0.86	(26,143)	637,374	0.83
1155C	POWERHOUSE RENOVATIONS	2118	40-SQ	0	26,446	661	2.50	(5)	657	2.48
1155D	SPILLWAY	2118	80-R3	0	14,942,733	192,918	1.29	(2,120)	190,798	1.28
1155E	WATER CONTROL SYSTEMS	2118	65-R4	0	17,167,202	270,456	1.58	(87,089)	183,367	1.07
1155F	ROADS AND SITE IMPROVEMENTS	2118	50-R3	0	1,563,205	31,397	2.01	(2,212)	29,185	1.87
1155G	TURBINES AND GENERATORS	2118	60-S3	0	91,716,371	1,582,037	1.72	12,804	1,594,841	1.74
1155H	GOVERNORS AND EXCITATION SYSTEM	2118	50-R4	0						2.13 *
1155L	LICENCE RENEWAL	2118	50-SQ	0						2.00 *
1155P	A/C ELECTRICAL POWER SYSTEMS	2118	55-R4	0	21,641,608	394,933	1.82	(63,837)	331,096	1.53
1155Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2118	25-S2	0	3,606,713	130,632	3.62	(8,425)	122,207	3.39
1155R	AUXILIARY STATION PROCESSES	2118	50-R2	0	13,685,752	308,674	2.26	(26,623)	282,051	2.06
1155X	SUPPORT BUILDINGS	2118	65-S3	0	7,885,397	129,073	1.64	(2,018)	127,055	1.61
1155W	SUPPORT BUILDING RENOVATIONS	2118	20-SQ	0						5.00
	TOTAL JENPEG				**265,579,412**	**3,851,491**	**1.45**	**(215,362)**	**3,636,129**	**1.37**
	LAKE WINNIPEG REGULATION									
1160A	DAMS, DYKES AND WEIRS		125-R4	0	110,416,014	928,951	0.84	(78,997)	849,954	0.77
1160L	LICENCE RENEWAL		50-SQ	0	250,000	5,000	2.00	41	5,041	2.02
1160Z	COMMUNITY DEVELOPMENT COSTS ***		85-SQ	0	436,787,857	5,154,097	1.18		5,154,097	1.18 **
	TOTAL LAKE WINNIPEG REGULATION				**547,453,871**	**6,088,048**	**1.11**	**(78,956)**	**6,009,092**	**1.10**
	CHURCHILL RIVER DIVERSION									
1165A	DAMS, DYKES AND WEIRS		125-R4	0	120,816,679	1,015,938	0.84	(16,301)	999,637	0.83
1165D	SPILLWAY		80-R3	0	59,622,870	774,328	1.30	13,829	788,157	1.32
1165E	WATER CONTROL SYSTEMS		65-R4	0	18,858,667	296,843	1.57	(108,831)	188,012	1.00
1165F	ROADS AND SITE IMPROVEMENTS		50-R3	0	7,284,036	139,977	1.92	(10,409)	129,568	1.78
1165L	LICENCE RENEWAL		50-SQ	0						2.00 *
1165P	A/C ELECTRICAL POWER SYSTEMS		55-R4	0	1,710,889	31,121	1.82	(4,201)	26,920	1.57
1165Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	0	1,541,737	41,946	2.72	(5,504)	36,442	2.36
1165R	AUXILIARY STATION PROCESSES		50-R2	0	1,864,257	41,826	2.24	(2,493)	39,333	2.11
1165X	SUPPORT BUILDINGS		65-S3	0	79,309	1,309	1.65	11	1,320	1.66
1165W	SUPPORT BUILDING RENOVATIONS		20-SQ	0						5.00 *
1165Z	COMMUNITY DEVELOPMENT COSTS ***		90-SQ	0	351,065,147	3,896,823	1.11	(150,766)	3,746,057	1.07
	TOTAL CHURCHILL RIVER DIVERSION				**562,843,590**	**6,240,111**	**1.11**	**(284,664)**	**5,955,447**	**1.06**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	LONG SPRUCE									
1170A	DAMS, DYKES AND WEIRS	2118	125-R4	0	65,392,344	565,144	0.86	(20,520)	544,624	0.83
1170B	POWERHOUSE	2118	125-R4	0	143,800,935	1,240,724	0.86	(45,819)	1,194,905	0.83
1170C	POWERHOUSE RENOVATIONS	2118	40-SQ	0						2.50 *
1170D	SPILLWAY	2118	80-R3	0	42,273,617	549,842	1.30	(1,203)	548,639	1.30
1170E	WATER CONTROL SYSTEMS	2118	65-R4	0	57,946,281	909,794	1.57	(456,764)	453,030	0.78
1170F	ROADS AND SITE IMPROVEMENTS	2118	50-R3	0	1,376,630	27,626	2.01	(1,913)	25,713	1.87
1170G	TURBINES AND GENERATORS	2118	60-S3	0	143,328,643	2,453,827	1.71	(25,472)	2,428,355	1.69
1170H	GOVERNORS AND EXCITATION SYSTEM	2118	50-R4	0	145,844	3,092	2.12	(58)	3,034	2.08
1170L	LICENCE RENEWAL	2118	50-SQ	0						2.00 *
1170P	A/C ELECTRICAL POWER SYSTEMS	2118	55-R4	0	30,610,740	560,009	1.83	(99,219)	460,790	1.51
1170Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2118	25-S2	0	13,111,957	517,179	3.94	(9,467)	507,712	3.87
1170R	AUXILIARY STATION PROCESSES	2118	50-R2	0	12,385,777	245,631	1.98	(56,511)	189,120	1.53
1170X	SUPPORT BUILDINGS	2118	65-S3	0	160,484	2,648	1.65	(20)	2,628	1.64
1170W	SUPPORT BUILDING RENOVATIONS	2118	20-SQ	0	205,681	10,284	5.00	(201)	10,083	4.90 *
	TOTAL LONG SPRUCE				**510,738,934**	**7,085,800**	**1.39**	**(717,168)**	**6,368,632**	**1.25**
	LIMESTONE									
1175A	DAMS, DYKES AND WEIRS	2131	125-R4	0	33,287,049	288,306	0.87	(4,255)	284,051	0.85
1175B	POWERHOUSE	2131	125-R4	0	461,590,745	3,999,247	0.87	(60,506)	3,938,741	0.85
1175C	POWERHOUSE RENOVATIONS	2131	40-SQ	0						2.50 *
1175D	SPILLWAY	2131	80-R3	0	201,416,380	2,731,494	1.36	22,825	2,754,319	1.37
1175E	WATER CONTROL SYSTEMS	2131	65-R4	0	116,325,934	1,875,202	1.61	(389,496)	1,485,706	1.28
1175F	ROADS AND SITE IMPROVEMENTS	2131	50-R3	0	17,384,603	361,105	2.08	(7,507)	353,598	2.03
1175G	TURBINES AND GENERATORS	2131	60-S3	0	404,329,629	7,181,521	1.78	134,341	7,315,862	1.81
1175H	GOVERNORS AND EXCITATION SYSTEM	2131	50-R4	0	16,598,509	344,021	2.07	(19,135)	324,886	1.96
1175L	LICENCE RENEWAL	2131	50-SQ	0						2.00 *
1175P	A/C ELECTRICAL POWER SYSTEMS	2131	55-R4	0	144,588,941	2,741,516	1.90	(233,699)	2,507,817	1.73
1175Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2131	25-S2	0	8,782,898	323,602	3.68	(17,789)	305,813	3.48
1175R	AUXILIARY STATION PROCESSES	2131	50-R2	0	36,388,654	760,107	2.09	(105,397)	654,711	1.80
1175X	SUPPORT BUILDINGS	2131	65-S3	0	5,707,366	93,812	1.64	(533)	93,279	1.63
1175W	SUPPORT BUILDING RENOVATIONS	2131	20-SQ	0	652,644	32,632	5.00	(709)	31,923	4.89
	TOTAL LIMESTONE				**1,447,053,352**	**20,732,565**	**1.43**	**(681,859)**	**20,050,706**	**1.39**
	WUSKWATIM									
1180A	DAMS, DYKES AND WEIRS	2152	125-R4	0	4,694,366	40,841	0.87	(228)	40,614	0.87
1180B	POWERHOUSE	2152	125-R4	0	18,227,672	158,581	0.87	(742)	157,839	0.87
1180C	POWERHOUSE RENOVATIONS	2152	40-SQ	0						2.50 *
1180D	SPILLWAY	2152	80-R3	0	2,875,828	42,306	1.47	(259)	42,047	1.46
1180E	WATER CONTROL SYSTEMS	2152	65-R4	0	3,087,285	50,631	1.64	(607)	50,024	1.62
1180F	ROADS AND SITE IMPROVEMENTS	2152	50-R3	0	2,495,203	57,889	2.32	(43)	57,846	2.32
1180G	TURBINES AND GENERATORS	2152	60-S3	0	4,652,074	83,272	1.79	(581)	82,691	1.78
1180H	GOVERNORS AND EXCITATION SYSTEM	2152	50-R4	0	169,166	3,603	2.13	(19)	3,584	2.12
1180P	A/C ELECTRICAL POWER SYSTEMS	2152	55-R4	0	1,691,663	32,649	1.93	(192)	32,457	1.92
1180Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2152	25-S2	0	1,141,873	51,841	4.54	(1,724)	50,117	4.39
1180R	AUXILIARY STATION PROCESSES	2152	50-R2	0	2,029,996	60,509	2.98	(1,093)	59,416	2.93
1180X	SUPPORT BUILDINGS	2152	65-S3	0	930,415	15,352	1.65	(60)	15,292	1.64
1180W	SUPPORT BUILDING RENOVATIONS	2152	20-SQ	0						5.00 *
	TOTAL WUSKWATIM				**41,995,540**	**597,474**	**1.42**	**(5,547)**	**591,927**	**1.41**
	INFRASTRUCTURE SUPPORTING GENERATION									
1199F	PROVINCIAL ROADS		50-R3	0	25,412,921	496,309	1.95	66,217	562,526	2.21
1199V	TOWN SITE BUILDINGS		55-R4	0	82,260,635	1,549,195	1.88	124,761	1,673,956	2.03
1199W	TOWN SITE BUILDING RENOVATIONS		20-SQ	0	27,027,620	1,351,381	5.00		1,351,381	5.00 **
1199Y	TOWN SITE OTHER INFRASTRUCTURE		45-R4	0	29,155,301	675,388	2.32	179,634	855,022	2.93
	TOTAL INFRASTRUCTURE SUPPORTING GENERATION				**163,856,477**	**4,072,273**	**2.49**	**370,612**	**4,442,885**	**2.71**
	TOTAL HYDRAULIC GENERATION				**5,445,593,386**	**85,969,964**	**1.58**	**(2,015,954)**	**83,954,010**	**1.54**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK (1)	LIFE SPAN DATE	SURVIVOR CURVE (2)	NET SALVAGE (3)	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014 (4)	CALCULATED ANNUAL ACCRUAL AMOUNT (5)	CALCULATED ANNUAL ACCRUAL RATE (%) (6)=(5)/(4)	ANNUAL PROVISION FOR TRUE-UP (7)	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE (8)=(5)+(7)	TOTAL DEPRECIATION RELATED TO LIFE RATE (%) (9)=(8)/(4)
	THERMAL GENERATION									
	BRANDON UNIT 5 (COAL)									
1205B	POWERHOUSE	2020	75-R5	0	11,729,518	437,982	3.73	90,227	528,209	4.50
1205C	POWERHOUSE RENOVATIONS	2020	40-SQ	0	396,538	58,727	14.81	4,236	62,963	15.88
1205F	ROADS AND SITE IMPROVEMENTS	2020	50-R3	0	4,018,549	178,659	4.45	36,822	215,481	5.36
1205G	TURBINES AND GENERATORS	2020	60-S3	0	19,611,168	981,163	5.00	140,953	1,122,116	5.72
1205H	GOVERNORS AND EXCITATION SYSTEM	2020	50-R4	0	2,343,861	118,834	5.07	10,629	129,463	5.52
1205J	STEAM GENERATOR AND AUXILIARIES	2020	60-S2.5	0	14,655,599	558,205	3.81	35,033	593,238	4.05
1205L	LICENCE RENEWAL	2020	50-SQ	0	2,198,654	325,621	14.81		325,621	14.81 **
1205P	A/C ELECTRICAL POWER SYSTEMS	2020	55-R4	0	8,026,175	307,402	3.83	65,326	372,728	4.64
1205Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2020	25-S2	0	25,758,061	1,097,565	4.26	37,357	1,134,922	4.41
1205R	AUXILIARY STATION PROCESSES	2020	50-R2	0	47,355,066	2,063,679	4.36	479,023	2,542,702	5.37
1205X	SUPPORT BUILDINGS	2020	65-S3	0	7,837,127	390,917	4.99	77,058	467,975	5.97
1205W	SUPPORT BUILDING RENOVATIONS	2020	20-SQ	0						16.67 *
	TOTAL BRANDON UNIT 5 (COAL)				**143,930,317**	**6,518,754**	**4.53**	**976,662**	**7,495,416**	**5.21**
	BRANDON UNITS 6 AND 7									
1210B	POWERHOUSE		75-R5	0	14,925,029	202,980	1.36	(15,626)	187,354	1.26
1210C	POWERHOUSE RENOVATIONS		40-SQ	0	144,571	3,614	2.50	(61)	3,553	2.46
1210G	TURBINES AND GENERATORS		60-S3	0	11,222,428	200,881	1.79	(16,963)	183,918	1.64
1210H	GOVERNORS AND EXCITATION SYSTEM		50-R4	0						2.13 *
1210K	COMBUSTION TURBINE		25-R3	0	143,303,747	5,950,408	4.15	(709,033)	5,241,375	3.66
1210L	LICENCE RENEWAL		50-SQ	0						2.00 *
1210M	COMBUSTION TURBINE OVERHAULS		15-SQ	0						6.67 *
1210P	A/C ELECTRICAL POWER SYSTEMS		55-R4	0	6,346,535	121,877	1.92	(8,981)	112,896	1.78
1210Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	0	1,295,814	57,854	4.46	2,093	59,947	4.63
1210R	AUXILIARY STATION PROCESSES		50-R2	0	10,639,560	243,178	2.29	(20,072)	223,106	2.10
	TOTAL BRANDON UNITS 6 AND 7				**187,877,685**	**6,780,792**	**3.61**	**(768,643)**	**6,012,150**	**3.20**
	SELKIRK									
1215B	POWERHOUSE		75-R5	0	6,808,812	91,507	1.34	(37,892)	53,615	0.79
1215C	POWERHOUSE RENOVATIONS		40-SQ	0	451,038	11,276	2.50	(236)	11,040	2.45
1215F	ROADS AND SITE IMPROVEMENTS		50-R3	0	1,630,443	32,325	1.98	(9,171)	23,154	1.42
1215G	TURBINES AND GENERATORS		60-S3	0	22,750,003	390,404	1.72	(120,866)	269,539	1.18
1215H	GOVERNORS AND EXCITATION SYSTEM		50-R4	0	17,307	360	2.08	(135)	225	1.30
1215J	STEAM GENERATOR AND AUXILIARIES		60-S2.5	0	51,721,352	923,129	1.78	(66,926)	856,203	1.66
1215L	LICENCE RENEWAL		50-SQ	0						2.00 *
1215P	A/C ELECTRICAL POWER SYSTEMS		55-R4	0	3,171,700	55,216	1.74	(22,653)	32,563	1.03
1215Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25-S2	0	5,286,066	201,329	3.81	(74,487)	126,842	2.40
1215R	AUXILIARY STATION PROCESSES		50-R2	0	14,897,376	312,820	2.10	(98,461)	214,360	1.44
1215X	SUPPORT BUILDINGS		65-S3	0	1,033,229	15,990	1.55	(4,338)	11,652	1.13
1215W	SUPPORT BUILDING RENOVATIONS		20-SQ	0						5.00 *
	TOTAL SELKIRK				**107,767,327**	**2,034,356**	**1.89**	**(435,165)**	**1,599,191**	**1.48**
	TOTAL THERMAL GENERATION				**439,575,329**	**15,333,902**	**3.49**	**(227,146)**	**15,106,757**	**3.44**
	TOTAL GENERATION				**5,885,168,715**	**101,303,866**	**1.72**	**(2,243,100)**	**99,060,766**	**1.68**
	DIESEL GENERATION									
1300B	BUILDINGS		25-R3	0	8,263,526	332,579	4.02	(70,719)	261,860	3.17
1300C	BUILDING RENOVATIONS		15-SQ	0	17,929	1,196	6.67		1,196	6.67 **
1300M	ENGINES AND GENERATORS - OVERHAULS		4-SQ	0	1,998,461	499,615	25.00		499,615	25.00 ****
1300N	ENGINES AND GENERATORS		22-R2	0	16,774,955	752,395	4.49	(293,961)	458,434	2.73
1300Q	ACCESSORY STATION EQUIPMENT		20-R3	0	15,892,750	801,997	5.05	(217,939)	584,058	3.67
1300T	FUEL STORAGE AND HANDLING		25-R2	0	5,083,046	204,385	4.02	(72,260)	132,125	2.60
	TOTAL DIESEL GENERATION				**48,030,666**	**2,592,167**	**5.40**	**(654,879)**	**1,937,288**	**4.03**

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)	
	TRANSMISSION										
2000F	ROADS, TRAILS AND BRIDGES		50-S2.5	0	10,686,118	234,154	2.19	(872)	233,283	2.18	
2000G	METAL TOWERS AND CONCRETE POLES		85-R4	0	481,955,524	5,953,867	1.24	(21,789)	5,932,078	1.23	
2000J	POLES AND FIXTURES		55-R3	0	117,066,069	2,279,899	1.95	(175,193)	2,104,706	1.80	
2000K	GROUND LINE TREATMENT		10-SQ	0	2,297,990	229,799	10.00		229,799	10.00	**
2000L	OVERHEAD CONDUCTOR AND DEVICES		80-R4	0	349,810,506	4,569,630	1.31	(722,139)	3,847,491	1.10	
2000M	UNDERGROUND CABLE AND DEVICES		45-R3	0	960,535	19,789	2.06	(2,393)	17,396	1.81	
2000Z	COMMUNITY DEVELOPMENT COSTS ***		79-SQ	0	17,625,510	223,844	1.27	(692)	223,152	1.27	
	TOTAL TRANSMISSION				**980,402,254**	**13,510,982**	**1.38**	**(923,077)**	**12,587,905**	**1.28**	
	SUBSTATIONS										
3000B	BUILDINGS		65-R4	0	167,465,733	2,680,403	1.60	(234,766)	2,445,637	1.46	
3000C	BUILDING RENOVATIONS		20-SQ	0	16,023,446	800,762	5.00		800,762	5.00	**
3000F	ROADS, STEEL STRUCTURES AND CIVIL SITE WORKS		50-R4	0	301,966,571	6,153,965	2.04	(841,411)	5,312,554	1.76	
3000J	POLES AND FIXTURES		45-R2.5	0	8,976,505	223,044	2.48	(8,863)	214,181	2.39	
3100R	POWER TRANSFORMERS		50-R1.5	0	346,530,004	7,539,426	2.18	871,546	8,410,972	2.43	
3100S	OTHER TRANSFORMERS		50-S1	0	112,490,470	2,488,670	2.21	48,344	2,537,014	2.26	
3100T	INTERRUPTING EQUIPMENT		50-R2.5	0	210,045,708	4,428,834	2.11	418,260	4,847,094	2.31	
3100U	OTHER STATION EQUIPMENT		45-R3	0	553,640,228	12,875,743	2.33	(698,222)	12,177,521	2.20	
3100V	ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	0	222,763,291	9,688,954	4.35	(995,206)	8,693,748	3.90	
3200M	SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS		65-R4	0	122,026,806	1,948,133	1.60	(91,136)	1,856,997	1.52	
3200N	SYNCHRONOUS CONDENSER OVERHAULS		15-SQ	0	47,815,173	2,974,008	6.22	(305,321)	2,668,687	5.58	
3200P	HVDC CONVERTER EQUIPMENT		30-S4	0	434,607,924	14,806,687	3.41	(3,470,499)	11,336,189	2.61	
3200S	HVDC SERIALIZED EQUIPMENT		30-R5	0	213,665,609	6,314,057	2.96	(1,901,847)	4,412,210	2.07	
3200U	HVDC ACCESSORY STATION EQUIPMENT		36-R3	0	169,254,248	4,966,929	2.93	(443,973)	4,522,956	2.67	
3200V	HVDC ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	0	47,913,305	1,716,535	3.58	(630,711)	1,085,824	2.27	
	TOTAL SUBSTATIONS				**2,975,185,020**	**79,606,150**	**2.68**	**(8,283,805)**	**71,322,345**	**2.40**	
	DISTRIBUTION										
4000A	CONCRETE DUCTLINE AND MANHOLES		75-R4	0	70,181,420	1,591,476	2.27	(12,836)	1,578,640	2.25	
4000C	CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT		30-R4	0	7,368,727	260,451	3.53	12,089	272,540	3.70	
4000G	METAL TOWERS		60-R3	0	10,853,698	204,435	1.88	(1,647)	202,788	1.87	
4000J	POLES AND FIXTURES		65-S0.5	0	668,956,088	11,903,877	1.78	(1,315,678)	10,588,200	1.58	
4000K	GROUND LINE TREATMENT		12-SQ	0	34,478,470	2,872,057	8.33	(324,784)	2,547,273	7.39	
4000L	OVERHEAD CONDUCTOR AND DEVICES		60-R1.5	0	717,203,040	13,594,658	1.90	(716,234)	12,878,424	1.80	
4000M	UNDERGROUND CABLE AND DEVICES - 66 KV		60-S1	0	27,891,495	571,645	2.05	5,756	577,401	2.07	
4000N	UNDERGROUND CABLE AND DEVICES - PRIMARY		60-R3	0	374,567,850	6,955,104	1.86	(110,875)	6,844,230	1.83	
4000P	UNDERGROUND CABLE AND DEVICES - SECONDARY		44-S3	0	249,788,828	6,006,451	2.40	(238,841)	5,767,610	2.31	
4000Q	SERIALIZED EQUIPMENT - OVERHEAD		45-R3	0	218,784,786	5,248,267	2.40	(644,591)	4,603,676	2.10	
4000R	DSC - HIGH VOLTAGE TRANSFORMERS		50-R3	0	25,320,598	582,285	2.30	10,847	593,132	2.34	
4000S	SERIALIZED EQUIPMENT - UNDERGROUND		42-R3	0	213,763,677	5,472,227	2.56	(343,272)	5,128,955	2.40	
4000V	ELECTRONIC EQUIPMENT		10-SQ	0	739,972	73,997	10.00	3,902	77,899	10.53	
4000W	SERVICES		35-R1.5	0	73,127,688	2,156,157	2.95	(774,911)	1,381,246	1.89	
4000X	STREET LIGHTING		45-R3	0	182,346,807	4,143,406	2.27	(137,946)	4,005,460	2.20	
	TOTAL DISTRIBUTION				**2,875,373,143**	**61,636,493**	**2.14**	**(4,589,021)**	**57,047,472**	**1.98**	
	METERS										
4900V	METERS - ELECTRONIC		15-L3	0	18,913,638	1,344,834	7.11	645,590	1,990,424	10.52	
4900Y	METERS - ANALOG		26-L1.5	0	19,622,056	561,924	2.86	264,999	826,923	4.21	
4900W	METERING EXCHANGES		15-SQ	0	33,545,519	2,237,486	6.67		2,237,486	6.67	**
4900Z	METERING TRANSFORMERS		50-R2.5	0	11,244,938	248,836	2.21	(10,186)	238,650	2.12	
	TOTAL METERS				**83,326,152**	**4,393,080**	**5.27**	**900,403**	**5,293,483**	**6.35**	

MANITOBA HYDRO

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	COMMUNICATION									
5000B	BUILDINGS		65-R3	0	6,955,504	114,216	1.64	(11,381)	102,835	1.48
5000C	BUILDING RENOVATIONS		20-SQ	0	3,486,352	174,093	4.99	(14,480)	159,613	4.58
5000D	BUILDING - SYSTEM CONTROL CENTRE		75-R4	0	15,857,686	223,593	1.41	(1,021)	222,572	1.40
5000G	COMMUNICATION TOWERS		60-R2	0	12,362,119	226,051	1.83	22,674	248,725	2.01
5000H	FIBRE OPTIC AND METALLIC CABLE		35-R2.5	0	131,559,381	4,154,573	3.16	383,034	4,537,607	3.45
5000J	CARRIER EQUIPMENT		20-R2.5	0	125,921,733	6,449,104	5.12	(273,374)	6,175,730	4.90
5000K	OPERATIONAL IT EQUIPMENT		5-SQ	0	4,821,768	964,354	20.00		964,354	20.00 **
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING		8-SQ	0	8,862,073	1,107,759	12.50	366,465	1,474,224	16.64
5000N	OPERATIONAL DATA NETWORK		8-SQ	0	18,817,356	2,352,169	12.50		2,352,169	12.50 **
5000R	POWER SYSTEM CONTROL		15-S1.5	0	14,264,753	899,867	6.31	(115,968)	783,899	5.50
	TOTAL COMMUNICATION				**342,908,725**	**16,665,779**	**4.86**	**355,948**	**17,021,727**	**4.96**
	MOTOR VEHICLES									
6000E	PASSENGER VEHICLES		11-S2	20	1,145,330	80,698	7.05	6,185	86,883	7.59
6000F	LIGHT TRUCKS		12-L4	10	69,461,644	5,233,353	7.53	3,681	5,237,034	7.54
6000G	HEAVY TRUCKS		19-L4	7	73,416,587	3,702,009	5.04	(20,202)	3,681,807	5.01
6000H	CONSTRUCTION EQUIPMENT		23-R2.5	20	21,130,532	784,060	3.71	(101,395)	682,665	3.23
6000I	LARGE SOFT-TRACK EQUIPMENT		27-L1.5	15	15,620,474	568,379	3.64	22,910	591,289	3.79
6000J	TRAILERS		35-S1	15	18,887,911	520,050	2.75	28,754	548,804	2.91
6000K	MISCELLANEOUS VEHICLES		13-L1	15	6,114,461	441,769	7.22	(38,514)	403,255	6.60
	TOTAL MOTOR VEHICLES				**205,776,939**	**11,330,318**	**5.51**	**(98,581)**	**11,231,737**	**5.46**
	BUILDINGS									
8000B	BUILDINGS - GENERAL		65-R3	0	103,251,540	1,707,332	1.65	76,004	1,783,336	1.73
8000C	BUILDING RENOVATIONS		20-SQ	0	37,401,024	1,870,051	5.00		1,870,051	5.00 **
8000D	BUILDING - 360 PORTAGE - CIVIL		100-R4	0	202,792,903	2,149,605	1.06	8,532	2,158,137	1.06
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL		45-R3	0	77,339,398	1,937,503	2.51	39,260	1,976,763	2.56
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE		10-SQ	0	1,007,453	100,745	10.00		100,745	10.00 **
	TOTAL BUILDINGS				**421,792,317**	**7,765,236**	**1.84**	**123,795**	**7,889,031**	**1.87**
	GENERAL EQUIPMENT									
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT		15-SQ	0	87,537,592	5,676,211	6.48		5,676,211	6.48 **
9000K	COMPUTER EQUIPMENT		5-SQ	0	49,555,418	9,911,084	20.00		9,911,084	20.00 **
9000L	OFFICE FURNITURE AND EQUIPMENT		20-SQ	0	26,318,137	1,315,907	5.00		1,315,907	5.00 **
9000M	HOT WATER TANKS		6-SQ	0	881,848	147,004	16.67		147,004	16.67 **
	TOTAL GENERAL EQUIPMENT				**164,292,994**	**17,050,206**	**10.38**		**17,050,206**	**10.38**
	EASEMENTS									
A100A	EASEMENTS		75-SQ	0	66,021,103	878,081	1.33		878,081	1.33 **
	TOTAL EASEMENTS				**66,021,103**	**878,081**	**1.33**		**878,081**	**1.33**
	COMPUTER SOFTWARE AND DEVELOPMENT									
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS		11-S6	0	111,692,382	10,141,380	9.08	(295,429)	9,845,951	8.82
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS		10-SQ	0	48,787,249	4,878,725	10.00	(426,046)	4,452,679	9.13
A200J	COMPUTER SOFTWARE - GENERAL		5-SQ	0	6,701,454	1,340,291	20.00		1,340,291	20.00 **
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL		5-SQ	0	4,652,481	930,496	20.00	339,877	1,270,373	27.31
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA		7-S3	0	10,313,958	1,566,520	15.19	(604,194)	962,326	9.33
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT				**182,147,524**	**18,857,412**	**10.35**	**(985,792)**	**17,871,620**	**9.81**
	TOTAL MANITOBA HYDRO				**14,230,425,552**	**335,589,770**	**2.36**	**(16,398,109)**	**319,191,661**	**2.24**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	WUSKWATIM POWER LIMITED PARTNERSHIP ("WPLP")									
	PROPERTY, PLANT AND EQUIPMENT									
	HYDRAULIC GENERATION									
1181A	WPLP - DAMS, DYKES AND WEIRS	2152	125-R4	0	148,498,470	1,291,937	0.87	(1,377)	1,290,561	0.87
1181B	WPLP - POWERHOUSE	2152	125-R4	0	569,576,645	4,955,317	0.87	(5,373)	4,949,945	0.87
1181C	WPLP - POWERHOUSE RENOVATIONS	2152	40-SQ	0						2.50 *
1181D	WPLP - SPILLWAY	2152	80-R3	0	90,639,257	1,323,333	1.46	(1,996)	1,321,338	1.46
1181E	WPLP - WATER CONTROL SYSTEMS	2152	65-R4	0	98,584,694	1,616,789	1.64	(16,675)	1,600,114	1.62
1181F	WPLP - ROADS AND SITE IMPROVEMENTS	2152	50-R3	0	79,988,348	1,855,730	2.32	(730)	1,855,000	2.32
1181G	WPLP - TURBINES AND GENERATORS	2152	60-S3	0	149,857,582	2,682,451	1.79	(322)	2,682,129	1.79
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM	2152	50-R4	0	5,167,019	110,058	2.13	(357)	109,701	2.12
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS	2152	55-R4	0	49,908,667	963,237	1.93	(7,597)	955,640	1.91
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS	2152	25-S2	0	37,311,999	1,693,965	4.54	(11,618)	1,682,348	4.51
1181R	WPLP - AUXILIARY STATION PROCESSES	2152	50-R2	0	66,497,960	1,828,694	2.75	(2,667)	1,826,027	2.75
1181X	WPLP - SUPPORT BUILDINGS	2152	65-S3	0	29,258,457	482,765	1.65	(1,082)	481,683	1.65
1181W	WPLP - SUPPORT BUILDING RENOVATIONS	2152	20-SQ	0						5.00 *
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND	2152	95-SQ	0	389,662	4,091	1.05	(300)	3,791	0.97
	TOTAL GENERATION				**1,325,678,762**	**18,808,367**	**1.42**	**(50,092)**	**18,758,276**	**1.41**
	SUBSTATIONS									
3081B	WPLP - BUILDINGS		65-R4	0	326,268	5,351	1.64	3	5,354	1.64
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK		50-R4	0	1,761,913	37,529	2.13	(66)	37,463	2.13
3181R	WPLP - POWER TRANSFORMERS		50-R1.5	0	4,482,057	138,496	3.09	913	139,409	3.11
3181T	WPLP - INTERRUPTING EQUIPMENT		50-R2.5	0	839,984	21,336	2.54	(12)	21,324	2.54
3181U	WPLP - OTHER STATION EQUIPMENT		45-R3	0	1,621,291	41,667	2.57	(86)	41,581	2.56
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	0	1,065,222	55,605	5.22	74	55,679	5.23
	TOTAL SUBSTATIONS				**10,096,734**	**299,984**	**2.97**	**827**	**300,811**	**2.98**
	COMMUNICATION									
5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE		35-R2.5	0	150,000	5,340	3.56	18	5,358	3.57
5081J	WPLP - CARRIER EQUIPMENT		20-R2.5	0	50,000	3,030	6.06	(88)	2,942	5.88
	TOTAL COMMUNICATION				**200,000**	**8,370**	**4.19**	**(70)**	**8,300**	**4.15**
	MOTOR VEHICLES									
6081G	WPLP - HEAVY TRUCKS		19-L4	7	46,325	2,404	5.19	(1,129)	1,275	2.75
6081H	WPLP - CONSTRUCTION EQUIPMENT		23-R2.5	20	42,012	1,785	4.25	81	1,866	4.44
6081J	WPLP - TRAILERS		35-S1	15	82,208	2,530	3.08	37	2,567	3.12
6081K	WPLP - MISCELLANEOUS VEHICLES		13-L1	15	54,399	4,980	9.15	142	5,122	9.42
	TOTAL MOTOR VEHICLES				**224,944**	**11,699**	**5.20**	**(869)**	**10,830**	**4.81**
	GENERAL EQUIPMENT									
9081K	WPLP - COMPUTER EQUIPMENT		5-SQ	0	21,228	4,246	20.00	(921)	3,325	15.66
	TOTAL GENERAL EQUIPMENT				**21,228**	**4,246**	**20.00**	**(921)**	**3,325**	**15.66**
	TOTAL WPLP PROPERTY, PLANT AND EQUIPMENT				**1,336,221,667**	**19,132,666**	**1.43**	**(51,125)**	**19,081,542**	**1.43**
	INTANGIBLE ASSETS									
	TRANSMISSION									
2080F	WPLP - ROADS, TRAILS AND BRIDGES		50-S2.5	0	1,439,812	31,820	2.21	(214)	31,606	2.20
2080G	WPLP - METAL TOWERS AND CONCRETE POLES		85-R4	0	106,632,518	1,332,906	1.25	(7,285)	1,325,621	1.24
2080J	WPLP - POLES AND FIXTURES		55-R3	0	430,084	9,075	2.11	(64)	9,011	2.10
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES		80-R4	0	29,011,058	385,847	1.33	(2,265)	383,582	1.32
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND		79-SQ	0	1,909,456	24,250	1.27	(109)	24,141	1.26
	TOTAL TRANSMISSION				**139,422,928**	**1,783,898**	**1.28**	**(9,937)**	**1,773,961**	**1.27**
	SUBSTATIONS									
3080B	WPLP - BUILDINGS		65-R4	0	11,080,091	181,714	1.64	102	181,816	1.64
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK		50-R4	0	44,652,522	951,099	2.13	(1,720)	949,380	2.13
3180R	WPLP - POWER TRANSFORMERS		50-R1.5	0	4,272,536	132,294	3.10	924	133,218	3.12
3180S	WPLP - OTHER TRANSFORMERS		50-S1	0	31,309,273	795,281	2.54	(7,620)	787,661	2.52
3180T	WPLP - INTERRUPTING EQUIPMENT		50-R2.5	0	25,624,773	651,702	2.54	(355)	651,347	2.54
3180U	WPLP - OTHER STATION EQUIPMENT		45-R3	0	19,617,296	504,273	2.57	(1,048)	503,225	2.57
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES		25-R2	0	19,286,904	1,008,197	5.23	1,215	1,009,412	5.23
	TOTAL SUBSTATIONS				**155,843,395**	**4,224,560**	**2.71**	**(8,501)**	**4,216,059**	**2.71**

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DEPRECIABLE WORK	LIFE SPAN DATE	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
	DISTRIBUTION									
4080J	WPLP - POLES AND FIXTURES		65-S0.5	0	187,208	4,130	2.21	(7)	4,123	2.20
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES		60-R1.5	0	315,541	8,318	2.64	41	8,359	2.65
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY		60-R3	0	819,462	15,898	1.94	26	15,924	1.94
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND		42-R3	0	29,630	815	2.75		815	2.75
	TOTAL DISTRIBUTION				**1,351,840**	**29,161**	**2.16**	**61**	**29,222**	**2.16**
	COMMUNICATION									
5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE		35-R2.5	0	4,463,440	158,898	3.56	533	159,431	3.57
5080J	WPLP - CARRIER EQUIPMENT		20-R2.5	0	2,508,284	152,013	6.06	(4,486)	147,527	5.88
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING		8-SQ	0	212,713	26,589	12.50	740	27,329	12.85
5080N	WPLP - OPERATIONAL DATA NETWORK		8-SQ	0	440,117	55,015	12.50	(2,678)	52,337	11.89
	TOTAL COMMUNICATION				**7,624,554**	**392,515**	**5.15**	**(5,892)**	**386,624**	**5.07**
	EASEMENTS									
A180A	WPLP - EASEMENTS		75-SQ	0	796,640	10,595	1.33		10,595	1.33 **
	TOTAL EASEMENTS				**796,640**	**10,595**	**1.33**		**10,595**	**1.33**
	TOTAL WPLP INTANGIBLE ASSETS				**305,039,358**	**6,440,729**	**2.11**	**(24,269)**	**6,416,460**	**2.10**
	TOTAL WUSKWATIM POWER LIMITED PARTNERSHIP				**1,641,261,025**	**25,573,395**		**(75,393)**	**25,498,002**	**1.55**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	GENERATION							
	HYDRAULIC GENERATION							
	GREAT FALLS							
1105A	DAMS, DYKES AND WEIRS	17,345,473	7,124,582	8,400,996	(1,276,414)	(17.92)	47.1	(27,100)
1105B	POWERHOUSE	7,990,993	3,442,557	4,120,534	(677,977)	(19.69)	46.5	(14,580)
1105C	POWERHOUSE RENOVATIONS	47,039	1,764	3,450	(1,686)	(95.56)	38.5	(44)
1105D	SPILLWAY	9,676,327	4,060,375	4,538,669	(478,294)	(11.78)	42.0	(11,388)
1105E	WATER CONTROL SYSTEMS	24,245,253	8,311,683	12,000,543	(3,688,860)	(44.38)	41.7	(88,462)
1105F	ROADS AND SITE IMPROVEMENTS	935,986	83,444	81,796	1,648	1.98	41.8	39
1105G	TURBINES AND GENERATORS	33,818,312	8,471,310	7,031,203	1,440,107	17.00	36.9	39,027
1105H	GOVERNORS AND EXCITATION SYSTEM	1,154,724	248,346	282,594	(34,248)	(13.79)	41.8	(819)
1105L	LICENCE RENEWAL							*
1105P	A/C ELECTRICAL POWER SYSTEMS	9,493,088	3,705,755	4,425,761	(720,006)	(19.43)	35.7	(20,168)
1105Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	19,506,209	8,957,204	10,107,853	(1,150,649)	(12.85)	15.4	(74,717)
1105R	AUXILIARY STATION PROCESSES	10,221,178	3,296,845	4,161,341	(864,496)	(26.22)	35.8	(24,148)
1105X	SUPPORT BUILDINGS	1,495,253	709,194	844,526	(135,332)	(19.08)	41.9	(3,230)
1105W	SUPPORT BUILDING RENOVATIONS	18,859	2,357	2,420	(63)	(2.68)	17.5	**
	TOTAL GREAT FALLS	**135,948,694**	**48,415,416**	**56,001,684**	**(7,586,268)**	**(15.67)**		**(225,590)**
	POINTE DU BOIS							
1110A	DAMS, DYKES AND WEIRS	20,718,888	2,963,034	6,598,928	(3,635,894)	(122.71)	25.2	(144,282)
1110B	POWERHOUSE	6,054,784	1,158,391	2,161,160	(1,002,769)	(86.57)	25.2	(39,792)
1110C	POWERHOUSE RENOVATIONS	1,897,782	76,601	119,782	(43,181)	(56.37)	25.2	(1,714)
1110D	SPILLWAY - ORIGINAL	7,797,851	4,137,021	2,809,584	1,327,437	32.09	1.0	1,327,437
1110E	WATER CONTROL SYSTEMS	4,466,812	1,135,217	2,540,169	(1,404,952)	(123.76)	25.1	(55,974)
1110F	ROADS AND SITE IMPROVEMENTS	1,055,707	85,749	94,281	(8,532)	(9.95)	24.7	(345)
1110G	TURBINES AND GENERATORS	31,899,060	5,841,172	12,317,530	(6,476,358)	(110.87)	25.2	(256,998)
1110H	GOVERNORS AND EXCITATION SYSTEM							*
1110L	LICENCE RENEWAL							*
1110P	A/C ELECTRICAL POWER SYSTEMS	7,759,986	1,169,031	2,390,470	(1,221,439)	(104.48)	25.1	(48,663)
1110Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,037,485	157,405	252,040	(94,635)	(60.12)	20.2	(4,685)
1110R	AUXILIARY STATION PROCESSES	5,357,425	828,032	1,169,630	(341,598)	(41.25)	23.9	(14,293)
1110X	SUPPORT BUILDINGS	882,202	175,610	307,773	(132,163)	(75.26)	25.2	(5,245)
1110W	SUPPORT BUILDING RENOVATIONS	347,164	78,612	143,680	(65,068)	(82.77)	16.2	(4,017)
	TOTAL POINTE DU BOIS	**89,275,145**	**17,805,875**	**30,905,028**	**(13,099,153)**	**(73.57)**		**751,430**
	POINTE DU BOIS - NEW							
1111A	DAMS, DYKES AND WEIRS							*
1111D	SPILLWAY							*
1111E	WATER CONTROL SYSTEMS							*
1111F	ROADS AND SITE IMPROVEMENTS							*
1111P	A/C ELECTRICAL POWER SYSTEMS							*
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS							*
1111R	AUXILIARY STATION PROCESSES							*
1111X	SUPPORT BUILDINGS							*
1111W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL POINTE DU BOIS - NEW	**0**	**0**	**0**	**0**			**0**
	SEVEN SISTERS							
1115A	DAMS, DYKES AND WEIRS	31,926,879	12,410,440	16,705,443	(4,295,003)	(34.61)	55.3	(77,667)
1115B	POWERHOUSE	13,653,945	6,481,597	8,791,628	(2,310,031)	(35.64)	53.9	(42,858)
1115C	POWERHOUSE RENOVATIONS	578,473	26,614	47,350	(20,736)	(77.92)	38.2	(543)
1115D	SPILLWAY	2,940,065	1,501,420	1,738,916	(237,496)	(15.82)	49.7	(4,779)
1115E	WATER CONTROL SYSTEMS	4,520,291	1,988,052	3,169,768	(1,181,716)	(59.44)	48.9	(24,166)
1115F	ROADS AND SITE IMPROVEMENTS	205,641	113,980	157,505	(43,525)	(38.19)	41.7	(1,044)
1115G	TURBINES AND GENERATORS	54,449,323	13,785,619	16,740,788	(2,955,169)	(21.44)	46.1	(64,103)
1115H	GOVERNORS AND EXCITATION SYSTEM	290,552	27,312	29,305	(1,993)	(7.30)	45.8	(44)
1115L	LICENCE RENEWAL							*
1115P	A/C ELECTRICAL POWER SYSTEMS	11,924,230	4,192,343	5,724,619	(1,532,276)	(36.55)	40.5	(37,834)
1115Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,960,007	2,522,740	2,975,298	(452,558)	(17.94)	17.3	(26,159)
1115R	AUXILIARY STATION PROCESSES	8,512,853	2,485,407	3,464,996	(979,589)	(39.41)	40.0	(24,490)
1115X	SUPPORT BUILDINGS	608,294	145,676	204,918	(59,242)	(40.67)	48.6	(1,219)
1115W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SEVEN SISTERS	**134,570,553**	**45,681,200**	**59,750,533**	**(14,069,333)**	**(30.80)**		**(304,905)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	SLAVE FALLS							
1120A	DAMS, DYKES AND WEIRS	954,684	104,875	119,419	(14,544)	(13.87)	57.0	(255)
1120B	POWERHOUSE	45,692,194	7,657,054	8,824,065	(1,167,011)	(15.24)	56.9	(20,510)
1120C	POWERHOUSE RENOVATIONS							*
1120D	SPILLWAY	1,241,273	134,121	146,272	(12,151)	(9.06)	53.8	(226)
1120E	WATER CONTROL SYSTEMS	318,933	42,372	56,956	(14,584)	(34.42)	52.0	(281)
1120F	ROADS AND SITE IMPROVEMENTS	37,971,797	2,959,776	2,320,038	639,738	21.61	45.3	14,122
1120G	TURBINES AND GENERATORS	12,246,529	2,473,927	2,622,376	(148,449)	(6.00)	46.3	(3,206)
1120H	GOVERNORS AND EXCITATION SYSTEM	336,652	18,011	20,980	(2,969)	(16.48)	46.9	(63)
1120L	LICENCE RENEWAL							*
1120P	A/C ELECTRICAL POWER SYSTEMS	21,631,850	3,314,190	3,766,359	(452,169)	(13.64)	46.2	(9,787)
1120Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,446,295	654,607	614,152	40,455	6.18	21.8	1,856
1120R	AUXILIARY STATION PROCESSES	5,288,154	548,463	410,993	137,470	25.06	43.6	3,153
1120X	SUPPORT BUILDINGS	3,306,577	656,819	391,664	265,155	40.37	48.8	5,434
1120W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SLAVE FALLS	**133,434,938**	**18,564,215**	**19,293,273**	**(729,058)**	**(3.93)**		**(9,764)**
	PINE FALLS							
1125A	DAMS, DYKES AND WEIRS	18,301,512	2,840,188	3,373,554	(533,366)	(18.78)	74.6	(7,150)
1125B	POWERHOUSE	10,060,843	4,880,966	5,899,390	(1,018,424)	(20.87)	62.7	(16,243)
1125C	POWERHOUSE RENOVATIONS	121,809	4,568	8,933	(4,365)	(95.55)	38.5	(113)
1125D	SPILLWAY	93,376	8,399	9,221	(822)	(9.79)	66.9	(12)
1125E	WATER CONTROL SYSTEMS	3,660,833	1,836,547	2,674,651	(838,104)	(45.63)	49.1	(17,069)
1125F	ROADS AND SITE IMPROVEMENTS	1,180,058	972,972	1,213,586	(240,614)	(24.73)	10.9	0 ****
1125G	TURBINES AND GENERATORS	9,318,154	5,543,090	6,336,912	(793,822)	(14.32)	35.5	(22,361)
1125H	GOVERNORS AND EXCITATION SYSTEM							*
1125L	LICENCE RENEWAL							*
1125P	A/C ELECTRICAL POWER SYSTEMS	5,096,978	2,063,748	2,569,620	(505,872)	(24.51)	44.6	(11,342)
1125Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	3,881,573	1,350,331	1,486,418	(136,087)	(10.08)	18.4	(7,396)
1125R	AUXILIARY STATION PROCESSES	3,976,778	1,558,858	2,058,171	(499,313)	(32.03)	38.0	(13,140)
1125X	SUPPORT BUILDINGS	336,412	108,674	122,122	(13,448)	(12.37)	45.4	(296)
1125W	SUPPORT BUILDING RENOVATIONS							*
1125Z	COMMUNITY DEVELOPMENT COSTS ***	26,531,770	1,467,298	1,457,155	10,143	0.69	73.7	**
	TOTAL PINE FALLS	**82,560,097**	**22,635,639**	**27,209,733**	**(4,574,094)**	**(20.21)**		**(95,123)**
	MCARTHUR FALLS							
1130A	DAMS, DYKES AND WEIRS	6,837,356	1,603,256	1,881,776	(278,520)	(17.37)	74.7	(3,729)
1130B	POWERHOUSE	9,358,105	4,482,933	5,321,399	(838,466)	(18.70)	64.2	(13,060)
1130C	POWERHOUSE RENOVATIONS	405,461	15,205	29,734	(14,529)	(95.55)	38.5	(377)
1130D	SPILLWAY	2,417,504	1,654,460	1,815,242	(160,782)	(9.72)	30.0	(5,359)
1130E	WATER CONTROL SYSTEMS	11,703,203	4,053,770	5,994,290	(1,940,520)	(47.87)	46.7	(41,553)
1130F	ROADS AND SITE IMPROVEMENTS	235,262	127,183	146,060	(18,877)	(14.84)	30.2	(625)
1130G	TURBINES AND GENERATORS	5,379,618	4,297,099	4,887,739	(590,640)	(13.75)	21.7	(27,218)
1130H	GOVERNORS AND EXCITATION SYSTEM	119,315	42,037	48,419	(6,382)	(15.18)	33.6	(190)
1130L	LICENCE RENEWAL							*
1130P	A/C ELECTRICAL POWER SYSTEMS	2,521,761	1,634,050	1,995,628	(361,578)	(22.13)	37.1	(9,746)
1130Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,275,876	825,733	948,698	(122,965)	(14.89)	15.8	(7,783)
1130R	AUXILIARY STATION PROCESSES	3,616,031	1,398,438	1,807,227	(408,789)	(29.23)	38.6	(10,590)
1130X	SUPPORT BUILDINGS							*
1130W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL MCARTHUR FALLS	**43,869,489**	**20,134,164**	**24,876,211**	**(4,742,047)**	**(23.55)**		**(120,231)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	KELSEY							
1135A	DAMS, DYKES AND WEIRS	9,296,418	2,445,185	1,995,524	449,661	18.39	78.0	5,765
1135B	POWERHOUSE	71,294,313	13,106,742	10,733,548	2,373,194	18.11	80.1	29,628
1135C	POWERHOUSE RENOVATIONS							*
1135D	SPILLWAY	7,196,926	3,574,023	2,682,256	891,767	24.95	41.3	21,592
1135E	WATER CONTROL SYSTEMS	35,342,564	5,158,780	5,265,558	(106,778)	(2.07)	56.8	(1,880)
1135F	ROADS AND SITE IMPROVEMENTS	12,310,412	4,135,040	3,327,740	807,300	19.52	31.2	25,875
1135G	TURBINES AND GENERATORS	146,383,857	12,072,000	7,088,935	4,983,065	41.28	54.6	91,265
1135H	GOVERNORS AND EXCITATION SYSTEM	6,948,606	449,401	299,117	150,284	33.44	46.9	3,204
1135L	LICENCE RENEWAL							*
1135P	A/C ELECTRICAL POWER SYSTEMS	40,494,515	3,769,418	1,709,859	2,059,559	54.64	48.7	42,291
1135Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	13,650,816	3,455,570	2,694,420	761,150	22.03	18.6	40,922
1135R	AUXILIARY STATION PROCESSES	9,929,302	3,240,170	2,947,898	292,272	9.02	37.3	7,836
1135X	SUPPORT BUILDINGS	13,448,502	2,560,473	1,989,351	571,122	22.31	52.8	10,817
1135W	SUPPORT BUILDING RENOVATIONS	1,598,817	138,067	303,374	(165,307)	(119.73)	18.3	(9,033)
	TOTAL KELSEY	**367,895,048**	**54,104,869**	**41,037,582**	**13,067,287**	**24.15**		**268,281**
	GRAND RAPIDS							
1140A	DAMS, DYKES AND WEIRS	56,613,946	19,094,872	22,287,282	(3,192,410)	(16.72)	69.9	(45,671)
1140B	POWERHOUSE	24,506,522	9,969,166	11,674,816	(1,705,650)	(17.11)	67.8	(25,157)
1140C	POWERHOUSE RENOVATIONS	31,603	2,245	4,823	(2,578)	(114.84)	37.7	(68)
1140D	SPILLWAY	5,451,760	3,151,173	3,370,471	(219,298)	(6.96)	38.0	(5,771)
1140E	WATER CONTROL SYSTEMS	15,982,492	9,497,427	13,943,141	(4,445,714)	(46.81)	51.7	(85,991)
1140F	ROADS AND SITE IMPROVEMENTS	2,581,475	1,974,678	2,275,494	(300,816)	(15.23)	21.0	(14,325)
1140G	TURBINES AND GENERATORS	113,213,625	34,431,429	36,013,270	(1,581,841)	(4.59)	43.5	(36,364)
1140H	GOVERNORS AND EXCITATION SYSTEM	1,922,915	70,981	65,897	5,084	7.16	48.3	105
1140L	LICENCE RENEWAL	83,122,204	4,106,639	4,023,652	82,987	2.02	47.5	**
1140P	A/C ELECTRICAL POWER SYSTEMS	8,240,545	3,369,694	4,032,021	(662,327)	(19.66)	39.9	(16,600)
1140Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	4,690,245	3,574,028	4,000,352	(426,324)	(11.93)	13.2	(32,297)
1140R	AUXILIARY STATION PROCESSES	12,334,108	2,656,650	3,299,269	(642,619)	(24.19)	43.3	(14,841)
1140X	SUPPORT BUILDINGS	8,700,819	3,018,653	3,123,329	(104,676)	(3.47)	44.4	(2,358)
1140W	SUPPORT BUILDING RENOVATIONS	6,828,234	1,130,282	1,052,948	77,334	6.84	16.5	**
1140Z	COMMUNITY DEVELOPMENT COSTS ***	135,205,073	17,970,822	23,917,914	(5,947,092)	(33.09)	68.7	(86,566)
	TOTAL GRAND RAPIDS	**479,425,566**	**114,018,739**	**133,084,678**	**(19,065,939)**	**(16.72)**		**(365,903)**
	KETTLE							
1145A	DAMS, DYKES AND WEIRS	45,280,663	16,017,958	18,812,620	(2,794,662)	(17.45)	79.6	(35,109)
1145B	POWERHOUSE	146,313,138	51,257,424	60,221,797	(8,964,373)	(17.49)	79.8	(112,336)
1145C	POWERHOUSE RENOVATIONS							*
1145D	SPILLWAY	25,406,960	13,389,468	14,521,245	(1,131,777)	(8.45)	41.8	(27,076)
1145E	WATER CONTROL SYSTEMS	19,033,816	10,979,076	16,006,736	(5,027,660)	(45.79)	39.8	(126,323)
1145F	ROADS AND SITE IMPROVEMENTS	556,723	36,325	33,226	3,099	8.53	47.2	66
1145G	TURBINES AND GENERATORS	99,163,384	42,879,930	42,015,133	864,797	2.02	36.4	23,758
1145H	GOVERNORS AND EXCITATION SYSTEM	6,930,643	2,644,363	2,924,493	(280,130)	(10.59)	36.4	(7,696)
1145L	LICENCE RENEWAL							*
1145P	A/C ELECTRICAL POWER SYSTEMS	38,779,613	3,655,631	3,020,872	634,759	17.36	49.6	12,798
1145Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	16,263,031	9,180,919	9,901,036	(720,117)	(7.84)	18.0	(40,007)
1145R	AUXILIARY STATION PROCESSES	19,306,615	7,829,214	10,172,476	(2,343,262)	(29.93)	42.2	(55,528)
1145X	SUPPORT BUILDINGS	2,456,258	116,120	41,873	74,247	63.94	60.8	1,221
1145W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL KETTLE	**419,490,845**	**157,986,428**	**177,671,508**	**(19,685,080)**	**(12.46)**		**(366,231)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	LAURIE RIVER							
1150A	DAMS, DYKES AND WEIRS	355,538	199,768	160,937	38,831	19.44	20.2	1,922
1150B	POWERHOUSE	7,664,146	2,735,471	2,400,365	335,106	12.25	20.2	16,589
1150C	POWERHOUSE RENOVATIONS							*
1150D	SPILLWAY	870,000	432,564	361,707	70,857	16.38	19.9	3,561
1150E	WATER CONTROL SYSTEMS	458,033	218,132	181,641	36,491	16.73	20.0	1,825
1150F	ROADS AND SITE IMPROVEMENTS	1,441,914	729,326	591,840	137,486	18.85	18.7	7,352
1150G	TURBINES AND GENERATORS	4,603,136	1,373,422	1,250,829	122,593	8.93	20.1	6,099
1150H	GOVERNORS AND EXCITATION SYSTEM	882,653	219,727	210,242	9,485	4.32	20.1	472
1150L	LICENCE RENEWAL							*
1150P	A/C ELECTRICAL POWER SYSTEMS	1,441,945	646,616	548,644	97,972	15.15	19.8	4,948
1150Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,220,047	869,418	723,194	146,224	16.82	7.6	19,240
1150R	AUXILIARY STATION PROCESSES	308,504	152,400	125,709	26,691	17.51	18.6	1,435
1150X	SUPPORT BUILDINGS	355,919	185,932	154,615	31,318	16.84	19.8	1,582
1150W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL LAURIE RIVER	**19,601,835**	**7,762,776**	**6,709,722**	**1,053,054**	**13.57**		**65,025**
	JENPEG							
1155A	DAMS, DYKES AND WEIRS	16,438,690	3,873,606	4,745,111	(871,505)	(22.50)	89.9	(9,694)
1155B	POWERHOUSE	76,905,294	23,672,643	25,902,609	(2,229,966)	(9.42)	85.3	(26,143)
1155C	POWERHOUSE RENOVATIONS	26,446	992	1,164	(172)	(17.30)	38.5	(5)
1155D	SPILLWAY	14,942,733	6,992,432	7,090,366	(97,934)	(1.40)	46.2	(2,120)
1155E	WATER CONTROL SYSTEMS	17,167,202	9,105,612	12,092,757	(2,987,145)	(32.81)	34.3	(87,089)
1155F	ROADS AND SITE IMPROVEMENTS	1,563,205	841,418	899,601	(58,183)	(6.91)	26.3	(2,212)
1155G	TURBINES AND GENERATORS	91,716,371	44,453,425	44,027,069	426,356	0.96	33.3	12,804
1155H	GOVERNORS AND EXCITATION SYSTEM							*
1155L	LICENCE RENEWAL							*
1155P	A/C ELECTRICAL POWER SYSTEMS	21,641,608	12,669,385	14,316,375	(1,646,990)	(13.00)	25.8	(63,837)
1155Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	3,606,713	2,449,745	2,537,369	(87,624)	(3.58)	10.4	(8,425)
1155R	AUXILIARY STATION PROCESSES	13,685,752	4,503,206	5,581,430	(1,078,224)	(23.94)	40.5	(26,623)
1155X	SUPPORT BUILDINGS	7,885,397	2,808,815	2,897,007	(88,192)	(3.14)	43.7	(2,018)
1155W	SUPPORT BUILDING RENOVATIONS							
	TOTAL JENPEG	**265,579,412**	**111,371,279**	**120,090,857**	**(8,719,578)**	**(7.83)**		**(215,362)**
	LAKE WINNIPEG REGULATION							
1160A	DAMS, DYKES AND WEIRS	110,416,014	29,800,992	37,195,119	(7,394,127)	(24.81)	93.6	(78,997)
1160L	LICENCE RENEWAL	250,000	7,500	5,500	2,000	26.67	48.5	41
1160Z	COMMUNITY DEVELOPMENT COSTS ***	436,787,857	83,190,304	89,681,066	(6,490,762)	(7.80)	69.0	**
	TOTAL LAKE WINNIPEG REGULATION	**547,453,871**	**112,998,796**	**126,881,685**	**(13,882,889)**	**(12.29)**		**(78,956)**
	CHURCHILL RIVER DIVERSION							
1165A	DAMS, DYKES AND WEIRS	120,816,679	34,665,142	36,151,776	(1,486,634)	(4.29)	91.2	(16,301)
1165D	SPILLWAY	59,622,870	26,676,170	26,015,124	661,046	2.48	47.8	13,829
1165E	WATER CONTROL SYSTEMS	18,858,667	10,150,376	13,850,625	(3,700,249)	(36.45)	34.0	(108,831)
1165F	ROADS AND SITE IMPROVEMENTS	7,284,036	4,679,563	4,896,073	(216,510)	(4.63)	20.8	(10,409)
1165L	LICENCE RENEWAL							*
1165P	A/C ELECTRICAL POWER SYSTEMS	1,710,889	1,055,168	1,153,461	(98,293)	(9.32)	23.4	(4,201)
1165Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,541,737	1,337,499	1,374,377	(36,878)	(2.76)	6.7	(5,504)
1165R	AUXILIARY STATION PROCESSES	1,864,257	564,804	661,280	(96,476)	(17.08)	38.7	(2,493)
1165X	SUPPORT BUILDINGS	79,309	9,628	9,018	610	6.33	57.6	11
1165W	SUPPORT BUILDING RENOVATIONS							*
1165Z	COMMUNITY DEVELOPMENT COSTS ***	351,065,147	76,145,342	86,834,635	(10,689,293)	(14.04)	70.9	(150,766)
	TOTAL CHURCHILL RIVER DIVERSION	**562,843,590**	**155,283,692**	**170,946,369**	**(15,662,677)**	**(10.09)**		**(284,664)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	LONG SPRUCE							
1170A	DAMS, DYKES AND WEIRS	65,392,344	19,386,946	21,155,780	(1,768,834)	(9.12)	86.2	(20,520)
1170B	POWERHOUSE	143,800,935	43,055,059	46,995,513	(3,940,454)	(9.15)	86.0	(45,819)
1170C	POWERHOUSE RENOVATIONS							*
1170D	SPILLWAY	42,273,617	19,428,996	19,485,540	(56,544)	(0.29)	47.0	(1,203)
1170E	WATER CONTROL SYSTEMS	57,946,281	32,277,161	46,254,138	(13,976,977)	(43.30)	30.6	(456,764)
1170F	ROADS AND SITE IMPROVEMENTS	1,376,630	739,302	790,381	(51,079)	(6.91)	26.7	(1,913)
1170G	TURBINES AND GENERATORS	143,328,643	85,860,170	86,535,183	(675,013)	(0.79)	26.5	(25,472)
1170H	GOVERNORS AND EXCITATION SYSTEM	145,844	32,465	34,739	(2,274)	(7.00)	39.5	(58)
1170L	LICENCE RENEWAL							*
1170P	A/C ELECTRICAL POWER SYSTEMS	30,610,740	18,570,578	20,941,915	(2,371,337)	(12.77)	23.9	(99,219)
1170Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	13,111,957	4,768,641	4,968,395	(199,754)	(4.19)	21.1	(9,467)
1170R	AUXILIARY STATION PROCESSES	12,385,777	6,543,651	8,340,714	(1,797,063)	(27.46)	31.8	(56,511)
1170X	SUPPORT BUILDINGS	160,484	28,445	29,547	(1,102)	(3.87)	54.3	(20)
1170W	SUPPORT BUILDING RENOVATIONS	205,681	25,710	29,224	(3,514)	(13.67)	17.5	(201) *
	TOTAL LONG SPRUCE	**510,738,934**	**230,717,124**	**255,561,069**	**(24,843,945)**	**(10.77)**		**(717,168)**
	LIMESTONE							
1175A	DAMS, DYKES AND WEIRS	33,287,049	6,530,746	6,948,969	(418,223)	(6.40)	98.3	(4,255)
1175B	POWERHOUSE	461,590,745	90,215,875	96,169,680	(5,953,805)	(6.60)	98.4	(60,506)
1175C	POWERHOUSE RENOVATIONS							*
1175D	SPILLWAY	201,416,380	61,904,239	60,573,556	1,330,683	2.15	58.3	22,825
1175E	WATER CONTROL SYSTEMS	116,325,934	42,529,729	59,122,248	(16,592,519)	(39.01)	42.6	(389,496)
1175F	ROADS AND SITE IMPROVEMENTS	17,384,603	8,086,176	8,304,641	(218,465)	(2.70)	29.1	(7,507)
1175G	TURBINES AND GENERATORS	404,329,629	162,252,176	157,214,379	5,037,797	3.10	37.5	134,341
1175H	GOVERNORS AND EXCITATION SYSTEM	16,598,509	7,753,221	8,287,095	(533,874)	(6.89)	27.9	(19,135)
1175L	LICENCE RENEWAL							*
1175P	A/C ELECTRICAL POWER SYSTEMS	144,588,941	62,117,403	69,759,355	(7,641,952)	(12.30)	32.7	(233,699)
1175Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	8,782,898	5,962,551	6,142,216	(179,665)	(3.01)	10.1	(17,789)
1175R	AUXILIARY STATION PROCESSES	36,388,654	15,806,242	19,242,169	(3,435,927)	(21.74)	32.6	(105,397)
1175X	SUPPORT BUILDINGS	5,707,366	1,971,943	1,995,437	(23,494)	(1.19)	44.1	(533)
1175W	SUPPORT BUILDING RENOVATIONS	652,644	113,017	124,711	(11,694)	(10.35)	16.5	(709)
	TOTAL LIMESTONE	**1,447,053,352**	**465,243,318**	**493,884,457**	**(28,641,139)**	**(6.16)**		**(681,859)**
	WUSKWATIM							
1180A	DAMS, DYKES AND WEIRS	4,694,366	39,246	66,472	(27,226)	(69.37)	119.7	(228)
1180B	POWERHOUSE	18,227,672	167,889	256,744	(88,855)	(52.92)	119.7	(742)
1180C	POWERHOUSE RENOVATIONS							*
1180D	SPILLWAY	2,875,828	47,561	68,024	(20,463)	(43.02)	78.9	(259)
1180E	WATER CONTROL SYSTEMS	3,087,285	71,240	109,857	(38,617)	(54.21)	63.6	(607)
1180F	ROADS AND SITE IMPROVEMENTS	2,495,203	86,833	88,897	(2,064)	(2.38)	48.5	(43)
1180G	TURBINES AND GENERATORS	4,652,074	93,177	127,378	(34,201)	(36.71)	58.9	(581)
1180H	GOVERNORS AND EXCITATION SYSTEM	169,166	5,084	5,989	(905)	(17.79)	48.6	(19)
1180P	A/C ELECTRICAL POWER SYSTEMS	1,691,663	49,058	59,318	(10,260)	(20.91)	53.5	(192)
1180Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,141,873	47,518	89,058	(41,540)	(87.42)	24.1	(1,724)
1180R	AUXILIARY STATION PROCESSES	2,029,996	36,430	90,536	(54,106)	(148.52)	49.5	(1,093)
1180X	SUPPORT BUILDINGS	930,415	21,464	25,301	(3,837)	(17.88)	63.6	(60)
1180W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL WUSKWATIM	**41,995,540**	**665,500**	**987,574**	**(322,074)**	**(48.40)**		**(5,547)**
	INFRASTRUCTURE SUPPORTING GENERATION							
1199F	PROVINCIAL ROADS	25,412,921	15,815,481	14,398,428	1,417,053	8.96	21.4	66,217
1199V	TOWN SITE BUILDINGS	82,260,635	27,316,943	22,775,639	4,541,304	16.62	36.4	124,761
1199W	TOWN SITE BUILDING RENOVATIONS	27,027,620	7,664,403	7,474,145	190,258	2.48	14.2	**
1199Y	TOWN SITE OTHER INFRASTRUCTURE	29,155,301	9,827,228	4,725,638	5,101,590	51.91	28.4	179,634
	TOTAL INFRASTRUCTURE SUPPORTING GENERATION	**163,856,477**	**60,624,055**	**49,373,849**	**11,250,206**	**18.56**		**370,612**
	TOTAL HYDRAULIC GENERATION	**5,445,593,386**	**1,644,013,085**	**1,794,265,811**	**(150,252,726)**	**(9.14)**		**(2,015,954)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	THERMAL GENERATION							
	BRANDON UNIT 5 (COAL)							
1205B	POWERHOUSE	11,729,518	9,430,609	8,961,429	469,180	4.98	5.2	90,227
1205C	POWERHOUSE RENOVATIONS	396,538	88,119	66,090	22,029	25.00	5.2	4,236
1205F	ROADS AND SITE IMPROVEMENTS	4,018,549	3,093,218	2,901,743	191,475	6.19	5.2	36,822
1205G	TURBINES AND GENERATORS	19,611,168	14,480,090	13,747,137	732,953	5.06	5.2	140,953
1205H	GOVERNORS AND EXCITATION SYSTEM	2,343,861	1,723,207	1,667,938	55,269	3.21	5.2	10,629
1205J	STEAM GENERATOR AND AUXILIARIES	14,655,599	11,765,735	11,583,564	182,171	1.55	5.2	35,033
1205L	LICENCE RENEWAL	2,198,654	488,585	484,127	4,458	0.91	5.2	**
1205P	A/C ELECTRICAL POWER SYSTEMS	8,026,175	6,438,198	6,105,036	333,162	5.17	5.1	65,326
1205Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25,758,061	20,969,204	20,804,835	164,369	0.78	4.4	37,357
1205R	AUXILIARY STATION PROCESSES	47,355,066	36,800,147	34,357,132	2,443,015	6.64	5.1	479,023
1205X	SUPPORT BUILDINGS	7,837,127	5,787,119	5,386,420	400,699	6.92	5.2	77,058
1205W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL BRANDON UNIT 5 (COAL)	**143,930,317**	**111,064,231**	**106,065,451**	**4,998,780**	**4.50**		**976,662**
	BRANDON UNITS 6 AND 7							
1210B	POWERHOUSE	14,925,029	2,334,117	3,326,364	(992,247)	(42.51)	63.5	(15,626)
1210C	POWERHOUSE RENOVATIONS	144,571	6,071	8,409	(2,338)	(38.52)	38.3	(61)
1210G	TURBINES AND GENERATORS	11,222,428	2,108,156	2,949,523	(841,367)	(39.91)	49.6	(16,963)
1210H	GOVERNORS AND EXCITATION SYSTEM							*
1210K	COMBUSTION TURBINE	143,303,747	66,633,080	76,984,957	(10,351,877)	(15.54)	14.6	(709,033)
1210L	LICENCE RENEWAL							*
1210M	COMBUSTION TURBINE OVERHAULS							*
1210P	A/C ELECTRICAL POWER SYSTEMS	6,346,535	1,374,752	1,768,122	(393,370)	(28.61)	43.8	(8,981)
1210Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	1,295,814	344,096	304,113	39,983	11.62	19.1	2,093
1210R	AUXILIARY STATION PROCESSES	10,639,560	2,741,473	3,546,367	(804,894)	(29.36)	40.1	(20,072)
	TOTAL BRANDON UNITS 6 AND 7	**187,877,685**	**75,541,745**	**88,887,855**	**(13,346,110)**	**(17.67)**		**(768,643)**
	SELKIRK							
1215B	POWERHOUSE	6,808,812	4,072,876	6,717,712	(2,644,836)	(64.94)	69.8	(37,892)
1215C	POWERHOUSE RENOVATIONS	451,038	16,132	25,253	(9,121)	(56.54)	38.6	(236)
1215F	ROADS AND SITE IMPROVEMENTS	1,630,443	814,813	1,158,719	(343,906)	(42.21)	37.5	(9,171)
1215G	TURBINES AND GENERATORS	22,750,003	8,843,753	14,850,769	(6,007,016)	(67.92)	49.7	(120,866)
1215H	GOVERNORS AND EXCITATION SYSTEM	17,307	7,740	11,634	(3,894)	(50.30)	28.8	(135)
1215J	STEAM GENERATOR AND AUXILIARIES	51,721,352	13,820,903	17,133,762	(3,312,859)	(23.97)	49.5	(66,926)
1215L	LICENCE RENEWAL							*
1215P	A/C ELECTRICAL POWER SYSTEMS	3,171,700	2,034,203	3,164,610	(1,130,407)	(55.57)	49.9	(22,653)
1215Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS	5,286,066	3,308,601	4,396,109	(1,087,508)	(32.87)	14.6	(74,487)
1215R	AUXILIARY STATION PROCESSES	14,897,376	6,352,714	10,468,362	(4,115,648)	(64.79)	41.8	(98,461)
1215X	SUPPORT BUILDINGS	1,033,229	510,832	737,298	(226,466)	(44.33)	52.2	(4,338)
1215W	SUPPORT BUILDING RENOVATIONS							*
	TOTAL SELKIRK	**107,767,327**	**39,782,567**	**58,664,226**	**(18,881,659)**	**(47.46)**		**(435,165)**
	TOTAL THERMAL GENERATION	**439,575,329**	**226,388,543**	**253,617,532**	**(27,228,989)**	**(12.03)**		**(227,146)**
	TOTAL GENERATION	**5,885,168,715**	**1,870,401,628**	**2,047,883,343**	**(177,481,715)**	**(9.49)**		**(2,243,100)**
	DIESEL GENERATION							
1300B	BUILDINGS	8,263,526	4,495,224	5,435,792	(940,568)	(20.92)	13.3	(70,719)
1300C	BUILDING RENOVATIONS	17,929	9,505	9,086	419	4.41	7.0	**
1300M	ENGINES AND GENERATORS - OVERHAULS	1,998,461	1,192,879	2,092,372	(899,493)	(75.41)	1.6	**
1300N	ENGINES AND GENERATORS	16,774,955	8,750,230	13,042,057	(4,291,827)	(49.05)	14.6	(293,961)
1300Q	ACCESSORY STATION EQUIPMENT	15,892,750	7,854,125	11,319,359	(3,465,234)	(44.12)	15.9	(217,939)
1300T	FUEL STORAGE AND HANDLING	5,083,046	2,532,202	3,724,492	(1,192,290)	(47.09)	16.5	(72,260)
	TOTAL DIESEL GENERATION	**48,030,666**	**24,834,165**	**35,623,157**	**(10,788,992)**	**(43.44)**		**(654,879)**

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	TRANSMISSION							
2000F	ROADS, TRAILS AND BRIDGES	10,686,118	1,520,555	1,558,816	(38,261)	(2.52)	43.9	(872)
2000G	METAL TOWERS AND CONCRETE POLES	481,955,524	116,392,064	117,832,337	(1,440,273)	(1.24)	66.1	(21,789)
2000J	POLES AND FIXTURES	117,066,069	38,581,258	45,781,675	(7,200,417)	(18.66)	41.1	(175,193)
2000K	GROUND LINE TREATMENT	2,297,990	997,647	929,181	68,466	6.86	5.5	**
2000L	OVERHEAD CONDUCTOR AND DEVICES	349,810,506	106,680,310	151,380,725	(44,700,415)	(41.90)	61.9	(722,139)
2000M	UNDERGROUND CABLE AND DEVICES	960,535	695,937	731,355	(35,418)	(5.09)	14.8	(2,393)
2000Z	COMMUNITY DEVELOPMENT COSTS ***	17,625,510	365,319	418,852	(53,533)	(14.65)	77.4	(692)
	TOTAL TRANSMISSION	**980,402,254**	**265,233,090**	**318,632,940**	**(53,399,850)**	**(20.13)**		**(923,077)**
	SUBSTATIONS							
3000B	BUILDINGS	167,465,733	51,080,029	62,935,699	(11,855,670)	(23.21)	50.5	(234,766)
3000C	BUILDING RENOVATIONS	16,023,446	2,702,989	2,768,723	(65,734)	(2.43)	16.6	**
3000F	ROADS, STEEL STRUCTURES AND CIVIL SITE WORKS	301,966,571	123,300,300	155,273,917	(31,973,617)	(25.93)	38.0	(841,411)
3000J	POLES AND FIXTURES	8,976,505	2,552,766	2,862,084	(309,318)	(12.12)	34.9	(8,863)
3100R	POWER TRANSFORMERS	346,530,004	134,670,853	104,341,044	30,329,809	22.52	34.8	871,546
3100S	OTHER TRANSFORMERS	112,490,470	40,848,946	39,113,400	1,735,546	4.25	35.9	48,344
3100T	INTERRUPTING EQUIPMENT	210,045,708	84,391,918	71,133,091	13,258,827	15.71	31.7	418,260
3100U	OTHER STATION EQUIPMENT	553,640,228	211,048,267	233,531,016	(22,482,749)	(10.65)	32.2	(698,222)
3100V	ELECTRONIC EQUIPMENT AND BATTERIES	222,763,291	83,649,988	104,250,748	(20,600,760)	(24.63)	20.7	(995,206)
3200M	SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	122,026,806	53,450,319	56,949,947	(3,499,628)	(6.55)	38.4	(91,136)
3200N	SYNCHRONOUS CONDENSER OVERHAULS	47,815,173	18,720,329	21,926,203	(3,205,874)	(17.13)	10.5	(305,321)
3200P	HVDC CONVERTER EQUIPMENT	434,607,924	180,239,083	252,425,453	(72,186,370)	(40.05)	20.8	(3,470,499)
3200S	HVDC SERIALIZED EQUIPMENT	213,665,609	134,584,297	179,848,253	(45,263,956)	(33.63)	23.8	(1,901,847)
3200U	HVDC ACCESSORY STATION EQUIPMENT	169,254,248	59,522,100	71,820,161	(12,298,061)	(20.66)	27.7	(443,973)
3200V	HVDC ELECTRONIC EQUIPMENT AND BATTERIES	47,913,305	29,999,923	45,452,340	(15,452,417)	(51.51)	24.5	(630,711)
	TOTAL SUBSTATIONS	**2,975,185,020**	**1,210,762,107**	**1,404,632,079**	**(193,869,972)**	**(16.01)**		**(8,283,805)**
	DISTRIBUTION							
4000A	CONCRETE DUCTLINE AND MANHOLES	70,181,420	16,712,489	17,333,603	(621,114)	(3.72)	48.4	(12,836)
4000C	CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT	7,368,727	870,947	549,371	321,576	36.92	26.6	12,089
4000G	METAL TOWERS	10,853,698	1,548,234	1,635,676	(87,442)	(5.65)	53.1	(1,647)
4000J	POLES AND FIXTURES	668,956,088	222,676,867	291,618,371	(68,941,504)	(30.96)	52.4	(1,315,678)
4000K	GROUND LINE TREATMENT	34,478,470	13,877,134	16,410,452	(2,533,318)	(18.26)	7.8	(324,784)
4000L	OVERHEAD CONDUCTOR AND DEVICES	717,203,040	248,538,924	282,631,667	(34,092,743)	(13.72)	47.6	(716,234)
4000M	UNDERGROUND CABLE AND DEVICES - 66 KV	27,891,495	4,447,607	4,145,427	302,180	6.79	52.5	5,756
4000N	UNDERGROUND CABLE AND DEVICES - PRIMARY	374,567,850	72,865,241	78,442,229	(5,576,988)	(7.65)	50.3	(110,875)
4000P	UNDERGROUND CABLE AND DEVICES - SECONDARY	249,788,828	72,689,286	80,594,930	(7,905,644)	(10.88)	33.1	(238,841)
4000Q	SERIALIZED EQUIPMENT - OVERHEAD	218,784,786	65,078,154	88,347,900	(23,269,746)	(35.76)	36.1	(644,591)
4000R	DSC - HIGH VOLTAGE TRANSFORMERS	25,320,598	1,919,685	1,413,120	506,565	26.39	46.7	10,847
4000S	SERIALIZED EQUIPMENT - UNDERGROUND	213,763,677	65,861,701	77,018,038	(11,156,337)	(16.94)	32.5	(343,272)
4000V	ELECTRONIC EQUIPMENT	739,972	152,768	121,945	30,823	20.18	7.9	3,902
4000W	SERVICES	73,127,688	34,231,867	58,331,604	(24,099,737)	(70.40)	31.1	(774,911)
4000X	STREET LIGHTING	182,346,807	80,480,744	84,563,957	(4,083,213)	(5.07)	29.6	(137,946)
	TOTAL DISTRIBUTION	**2,875,373,143**	**901,951,648**	**1,083,158,289**	**(181,206,641)**	**(20.09)**		**(4,589,021)**
	METERS							
4900V	METERS - ELECTRONIC	18,913,638	7,086,582	1,405,387	5,681,195	80.17	8.8	645,590
4900Y	METERS - ANALOG	19,622,056	14,228,048	11,286,557	2,941,491	20.67	11.1	264,999
4900W	METERING EXCHANGES	33,545,519	13,908,623	13,913,673	(5,050)	(0.04)	8.8	**
4900Z	METERING TRANSFORMERS	11,244,938	3,498,102	3,892,303	(394,201)	(11.27)	38.7	(10,186)
	TOTAL METERS	**83,326,152**	**38,721,355**	**30,497,921**	**8,223,434**	**21.24**		**900,403**

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TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	COMMUNICATION							
5000B	BUILDINGS	6,955,504	2,413,593	2,947,372	(533,779)	(22.12)	46.9	(11,381)
5000C	BUILDING RENOVATIONS	3,486,352	1,243,551	1,440,484	(196,933)	(15.84)	13.6	(14,480)
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,465,112	3,525,976	(60,864)	(1.76)	59.6	(1,021)
5000G	COMMUNICATION TOWERS	12,362,119	4,316,592	3,350,680	965,912	22.38	42.6	22,674
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	39,174,600	29,139,100	10,035,500	25.62	26.2	383,034
5000J	CARRIER EQUIPMENT	125,921,733	58,344,665	61,816,520	(3,471,855)	(5.95)	12.7	(273,374)
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,484,791	2,691,962	(207,171)	(8.34)	2.7	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,464,791	4,438,690	1,026,101	18.78	2.8	366,465
5000N	OPERATIONAL DATA NETWORK	18,817,356	7,986,904	8,136,535	(149,631)	(1.87)	4.7	**
5000R	POWER SYSTEM CONTROL	14,264,753	7,144,616	8,431,858	(1,287,242)	(18.02)	11.1	(115,968)
	TOTAL COMMUNICATION	**342,908,725**	**132,039,215**	**125,919,176**	**6,120,040**	**4.64**		**355,948**
	MOTOR VEHICLES							
6000E	PASSENGER VEHICLES	1,145,330	521,369	487,352	34,017	6.52	5.5	6,185
6000F	LIGHT TRUCKS	69,461,644	29,780,150	29,754,753	25,397	0.09	6.9	3,681
6000G	HEAVY TRUCKS	73,416,587	29,200,922	29,435,263	(234,341)	(0.80)	11.6	(20,202)
6000H	CONSTRUCTION EQUIPMENT	21,130,532	6,492,558	8,256,831	(1,764,273)	(27.17)	17.4	(101,395)
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	4,544,540	4,072,604	471,936	10.38	20.6	22,910
6000J	TRAILERS	18,887,911	5,278,772	4,536,914	741,859	14.05	25.8	28,754
6000K	MISCELLANEOUS VEHICLES	6,114,461	2,160,617	2,553,455	(392,838)	(18.18)	10.2	(38,514)
	TOTAL MOTOR VEHICLES	**205,776,939**	**77,978,928**	**79,097,171**	**(1,118,243)**	**(1.43)**		**(98,581)**
	BUILDINGS							
8000B	BUILDINGS - GENERAL	103,251,540	33,044,112	29,525,141	3,518,972	10.65	46.3	76,004
8000C	BUILDING RENOVATIONS	37,401,024	12,021,426	10,936,091	1,085,335	9.03	13.3	**
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	11,623,441	10,816,316	807,125	6.94	94.6	8,532
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	10,106,216	8,539,762	1,566,454	15.50	39.9	39,260
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7	**
	TOTAL BUILDINGS	**421,792,317**	**67,426,354**	**60,434,771**	**6,991,583**	**10.37**		**123,795**
	GENERAL EQUIPMENT							
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3	**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0	**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3	**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9	**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		
	EASEMENTS							
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8	**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		
	COMPUTER SOFTWARE AND DEVELOPMENT							
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,557,562	68,946,077	(1,388,515)	(2.06)	4.7	(295,429)
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,251,110	6,634,595	(3,383,485)	(104.07)	5.6	(604,194)
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**100,235,181**	**106,830,136**	**(6,594,955)**	**(6.58)**		**(985,792)**
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,778,607,417**	**5,381,231,843**	**(602,624,426)**			**(16,398,109)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	WUSKWATIM POWER LIMITED PARTNERSHIP ("WPLP")							
	PROPERTY, PLANT AND EQUIPMENT							
	HYDRAULIC GENERATION							
1181A	WPLP - DAMS, DYKES AND WEIRS	148,498,470	1,930,480	2,094,830	(164,350)	(8.51)	119.4	(1,377)
1181B	WPLP - POWERHOUSE	569,576,645	7,404,496	8,045,968	(641,472)	(8.66)	119.4	(5,373)
1181C	WPLP - POWERHOUSE RENOVATIONS							*
1181D	WPLP - SPILLWAY	90,639,257	1,985,000	2,141,648	(156,648)	(7.89)	78.5	(1,996)
1181E	WPLP - WATER CONTROL SYSTEMS	98,584,694	2,425,183	3,484,050	(1,058,867)	(43.66)	63.5	(16,675)
1181F	WPLP - ROADS AND SITE IMPROVEMENTS	79,988,348	2,783,595	2,819,016	(35,421)	(1.27)	48.5	(730)
1181G	WPLP - TURBINES AND GENERATORS	149,857,582	4,016,183	4,035,022	(18,839)	(0.47)	58.5	(322)
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM	5,167,019	165,345	182,665	(17,320)	(10.48)	48.5	(357)
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS	49,908,667	1,447,351	1,853,786	(406,435)	(28.08)	53.5	(7,597)
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS	37,311,999	2,540,947	2,813,959	(273,012)	(10.74)	23.5	(11,618)
1181R	WPLP - AUXILIARY STATION PROCESSES	66,497,960	2,739,716	2,869,313	(129,597)	(4.73)	48.6	(2,667)
1181X	WPLP - SUPPORT BUILDINGS	29,258,457	725,610	794,301	(68,691)	(9.47)	63.5	(1,082)
1181W	WPLP - SUPPORT BUILDING RENOVATIONS							*
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND	389,662	6,153	34,187	(28,034)	(455.62)	93.5	(300)
	TOTAL GENERATION	**1,325,678,762**	**28,170,059**	**31,168,746**	**(2,998,687)**	**(10.64)**		**(50,092)**
	SUBSTATIONS							
3081B	WPLP - BUILDINGS	326,268	8,026	7,829	198	2.46	63.5	3
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	1,761,913	56,381	59,583	(3,202)	(5.68)	48.5	(66)
3181R	WPLP - POWER TRANSFORMERS	4,482,057	207,967	163,394	44,573	21.43	48.8	913
3181T	WPLP - INTERRUPTING EQUIPMENT	839,984	32,003	32,599	(596)	(1.86)	48.6	(12)
3181U	WPLP - OTHER STATION EQUIPMENT	1,621,291	62,582	66,315	(3,733)	(5.97)	43.5	(86)
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	1,065,222	83,407	81,652	1,755	2.10	23.6	74
	TOTAL SUBSTATIONS	**10,096,734**	**450,366**	**411,371**	**38,995**	**8.66**		**827**
	COMMUNICATION							
5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE	150,000	8,010	7,392	619	7.72	33.6	18
5081J	WPLP - CARRIER EQUIPMENT	50,000	4,545	6,184	(1,639)	(36.06)	18.6	(88)
	TOTAL COMMUNICATION	**200,000**	**12,555**	**13,575**	**(1,020)**	**(8.13)**		**(70)**
	MOTOR VEHICLES							
6081G	WPLP - HEAVY TRUCKS	46,325	3,606	23,363	(19,757)	(547.90)	17.5	(1,129)
6081H	WPLP - CONSTRUCTION EQUIPMENT	42,012	2,675	923	1,753	65.51	21.6	81
6081J	WPLP - TRAILERS	82,208	3,794	2,568	1,226	32.31	33.5	37
6081K	WPLP - MISCELLANEOUS VEHICLES	54,399	7,472	5,825	1,647	22.04	11.6	142
	TOTAL MOTOR VEHICLES	**224,944**	**17,547**	**32,679**	**(15,132)**	**(86.24)**		**(869)**
	GENERAL EQUIPMENT							
9081K	WPLP - COMPUTER EQUIPMENT	21,228	6,368	9,591	(3,223)	(50.60)	3.5	(921)
	TOTAL GENERAL EQUIPMENT	**21,228**	**6,368**	**9,591**	**(3,223)**	**(50.60)**		**(921)**
	TOTAL WPLP PROPERTY, PLANT AND EQUIPMENT	**1,336,221,667**	**28,656,895**	**31,635,962**	**(2,979,067)**	**(10.40)**		**(51,125)**
	INTANGIBLE ASSETS							
	TRANSMISSION							
2080F	WPLP - ROADS, TRAILS AND BRIDGES	1,439,812	47,802	58,197	(10,395)	(21.75)	48.5	(214)
2080G	WPLP - METAL TOWERS AND CONCRETE POLES	106,632,518	2,004,691	2,613,013	(608,322)	(30.34)	83.5	(7,285)
2080J	WPLP - POLES AND FIXTURES	430,084	13,591	16,997	(3,406)	(25.06)	53.5	(64)
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES	29,011,058	580,221	758,010	(177,789)	(30.64)	78.5	(2,265)
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND	1,909,456	36,261	44,679	(8,418)	(23.22)	77.5	(109)
	TOTAL TRANSMISSION	**139,422,928**	**2,682,566**	**3,490,895**	**(808,329)**	**(30.13)**		**(9,937)**
	SUBSTATIONS							
3080B	WPLP - BUILDINGS	11,080,091	270,675	264,222	6,453	2.38	63.5	102
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	44,652,522	1,426,444	1,509,841	(83,397)	(5.85)	48.5	(1,720)
3180R	WPLP - POWER TRANSFORMERS	4,272,536	196,586	151,476	45,110	22.95	48.8	924
3180S	WPLP - OTHER TRANSFORMERS	31,309,273	1,186,516	1,556,083	(369,567)	(31.15)	48.5	(7,620)
3180T	WPLP - INTERRUPTING EQUIPMENT	25,624,773	962,589	979,829	(17,240)	(1.79)	48.6	(355)
3180U	WPLP - OTHER STATION EQUIPMENT	19,617,296	751,703	797,278	(45,575)	(6.06)	43.5	(1,048)
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	19,286,904	1,496,897	1,468,111	28,786	1.92	23.7	1,215
	TOTAL SUBSTATIONS	**155,843,395**	**6,291,410**	**6,726,839**	**(435,429)**	**(6.92)**		**(8,501)**

WUSKWATIM POWER LIMITED PARTNERSHIP

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE		PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	
					AMOUNT	PERCENT			
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	
	DISTRIBUTION								
4080J	WPLP - POLES AND FIXTURES	187,208	4,531	4,986	(455)	(10.05)	63.9	(7)	
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES	315,541	12,315	9,882	2,433	19.75	58.8	41	
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY	819,462	23,846	22,302	1,545	6.48	58.5	26	
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND	29,630	1,221	1,239	(18)	(1.43)	40.6		
	TOTAL DISTRIBUTION	**1,351,840**	**41,913**	**38,409**	**3,504**	**8.36**		**61**	
	COMMUNICATION								
5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE	4,463,440	238,348	220,436	17,912	7.52	33.6	533	
5080J	WPLP - CARRIER EQUIPMENT	2,508,284	227,846	311,283	(83,437)	(36.62)	18.6	(4,486)	
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING	212,713	39,884	35,076	4,808	12.06	6.5	740	
5080N	WPLP - OPERATIONAL DATA NETWORK	440,117	82,522	99,932	(17,410)	(21.10)	6.5	(2,678)	
	TOTAL COMMUNICATION	**7,624,554**	**588,600**	**666,727**	**(78,127)**	**(13.27)**		**(5,892)**	
	EASEMENTS								
A180A	WPLP - EASEMENTS	796,640	13,009	12,601	408	3.14	73.8		**
	TOTAL EASEMENTS	**796,640**	**13,009**	**12,601**	**408**	**3.14**			
	TOTAL WPLP INTANGIBLE ASSETS	**305,039,358**	**9,617,498**	**10,935,471**	**(1,317,973)**	**(13.70)**		**(24,269)**	
	TOTAL WUSKWATIM POWER LIMITED PARTNERSHIP	**1,641,261,025**	**38,274,393**	**42,571,433**	**(4,297,040)**			**(75,393)**	

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.

APPENDIX A

ESTIMATION OF SURIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

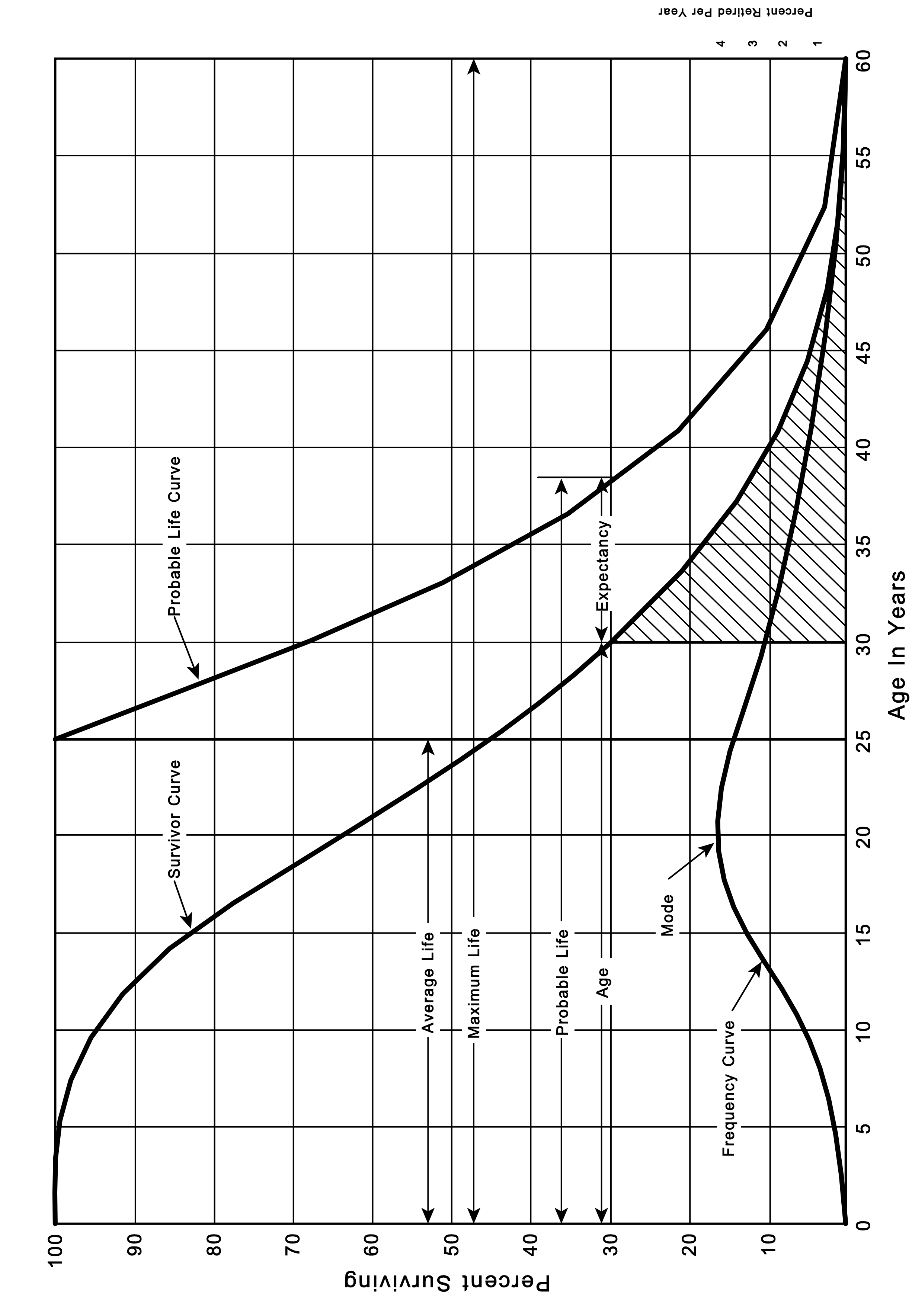

Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

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[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

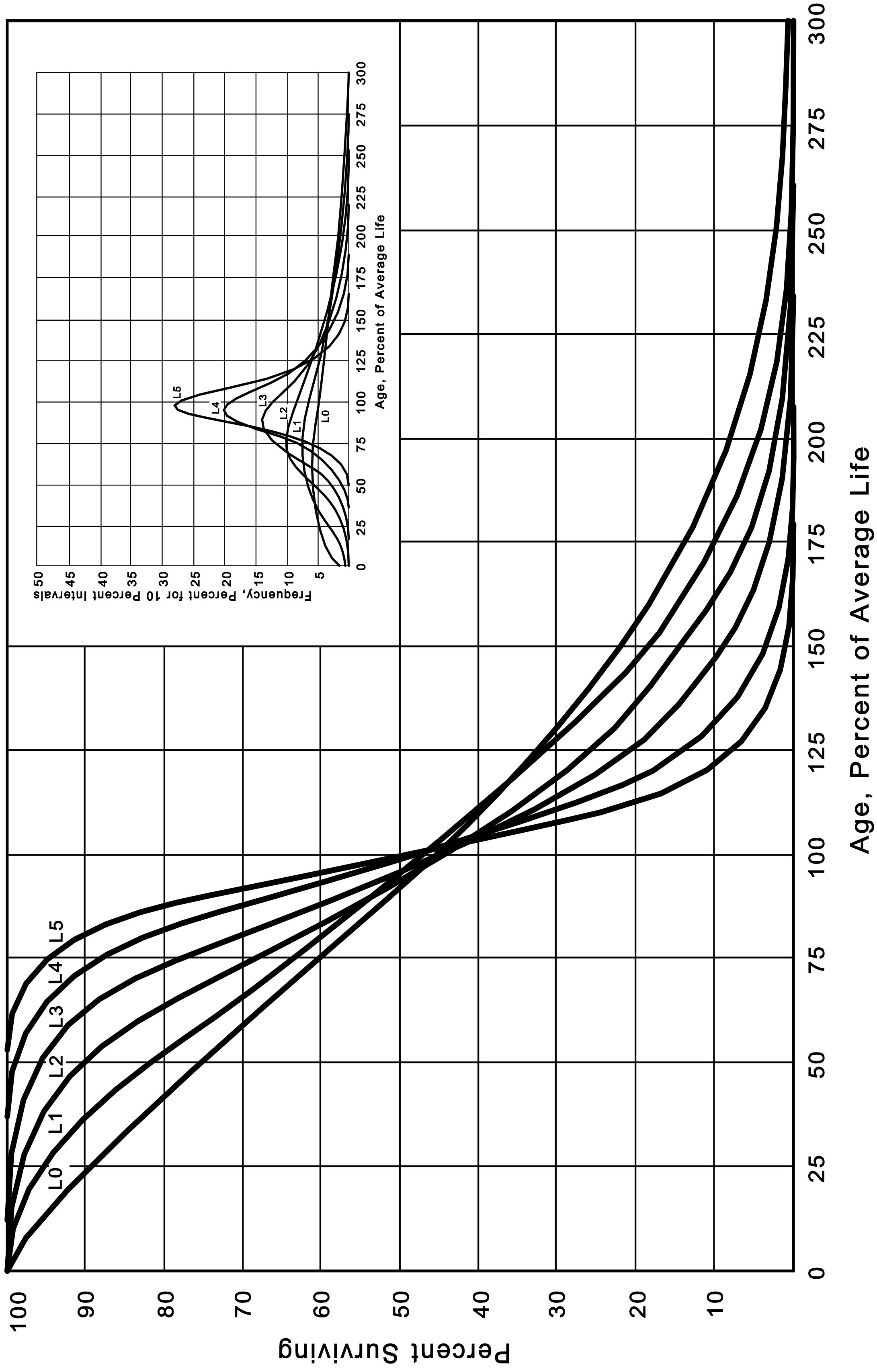

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

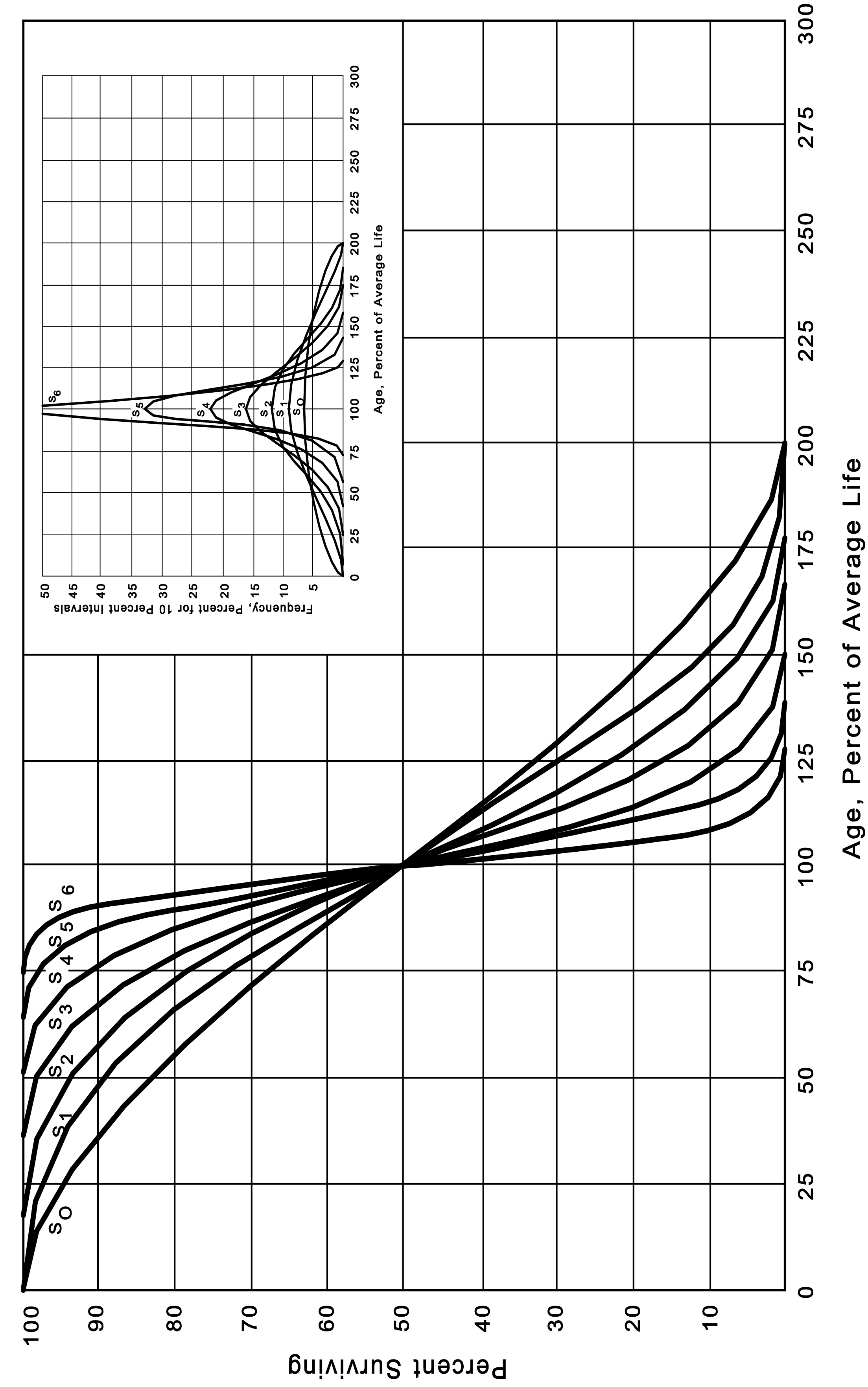

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

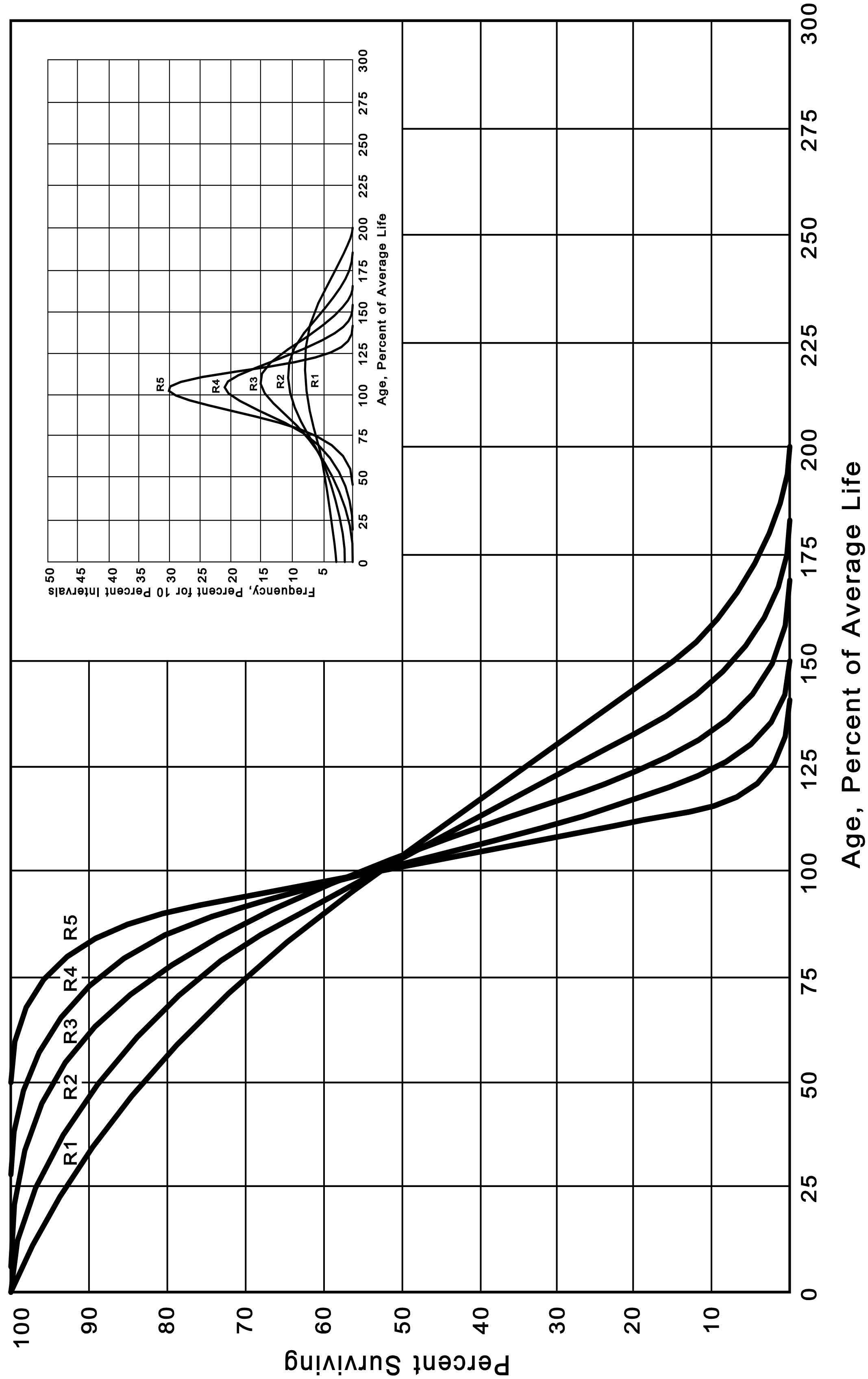

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

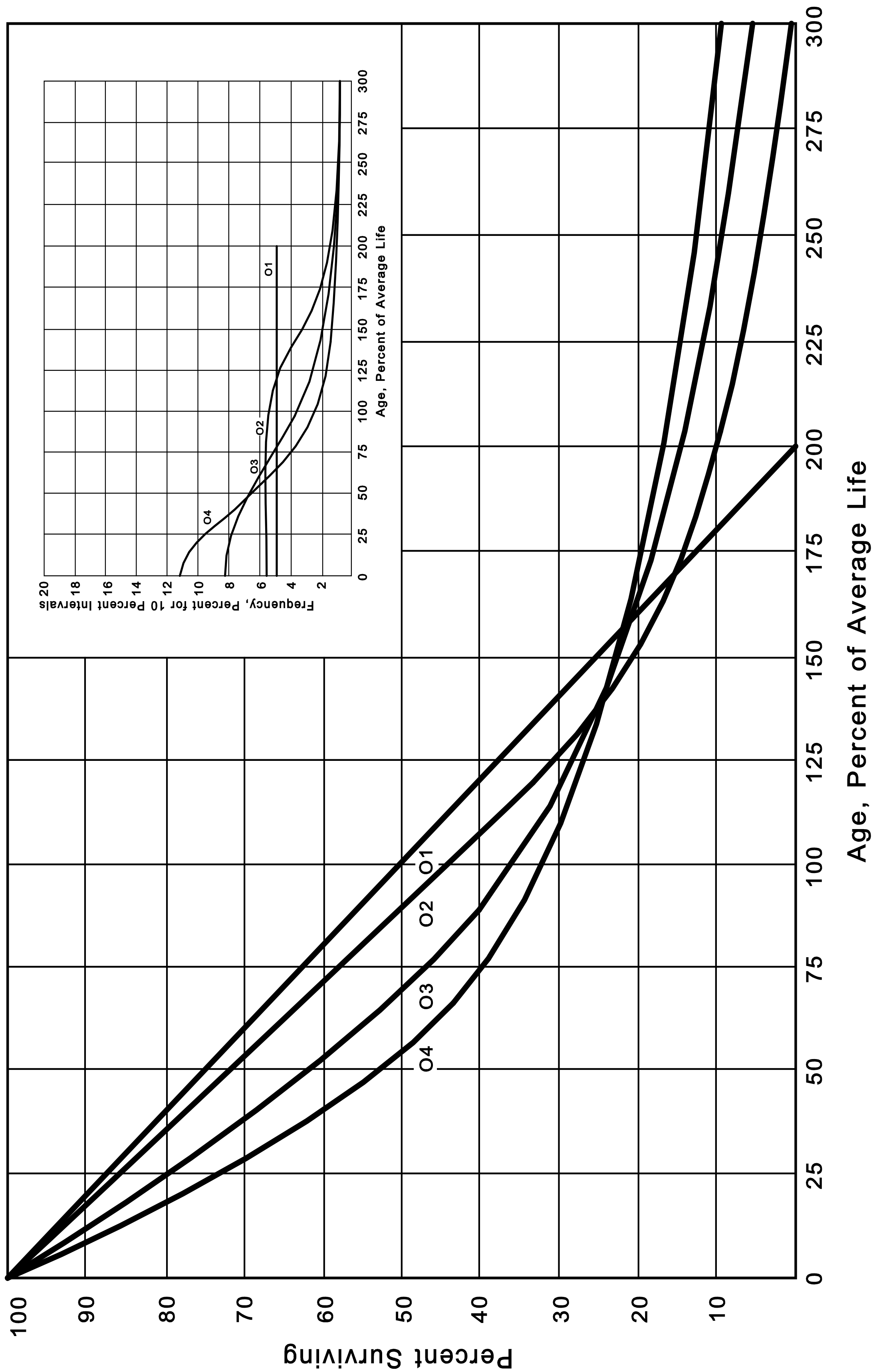

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the <u>experience band</u>, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the <u>placement band</u>. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2004-2013 during which there were placements during the years 1999-2013. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 1999 were

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[4] Winfrey, Robley, Supra Note 1.
[5] Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6] Wolf, Frank K. and W. Chester Fitch. <u>Depreciation Systems</u>. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2004-2013
SUMMARIZED BY AGE INTERVAL

Experience Band 2004-2013 | Placement Band 1999-2013

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1999	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2000	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2001	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2002	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2003	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2004	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2005		5	11	12	13	14	15	16	18	20	113	7½-8½
2006			6	12	13	15	16	17	19	19	124	6½-7½
2007				6	13	15	16	17	19	19	131	5½-6½
2008					7	14	16	17	19	20	143	4½-5½
2009						8	18	20	22	23	146	3½-4½
2010							9	20	22	25	150	2½-3½
2011								11	23	25	151	1½-2½
2012									11	24	153	½-1½
2013										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2004-2013
SUMMARIZED BY AGE INTERVAL

Experience Band 2004-2013 | Placement Band 1999-2013

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1999	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2000	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2001	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2002	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2003	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2004	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2005		-	-	-	-	-	-	-	-	-	-	7½-8½
2006			-	-	-	-	-	-	-	-	-	6½-7½
2007				-	-	-	-	(12)[b]	-	-	-	5½-6½
2008					-	-	-	-	22[a]	-	-	4½-5½
2009						-	-	(19)[b]	-	-	10	3½-4½
2010							-	-	-	-	-	2½-3½
2011								-	-	(102)[c]	(121)	1½-2½
2012									-	-	-	½-1½
2013												0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

retired in 2004. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2004 retirements of 1999 installations and ending with the 2013 retirements of the 2008 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2004 through 2013 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2004-2013
SUMMARIZED BY AGE INTERVAL

Experience Band 2004-2013

Placement Band 1999-2013

Year Placed	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total at Beginning of Age Interval	Age Interval
	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year											
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1999	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2000	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2001	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2002	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2003	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2004	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2005		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2006			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2007				580[a]	574	561	546	530	501	482	3,057	5½-6½
2008					660[a]	653	639	623	628	609	3,789	4½-5½
2009						750[a]	742	724	685	663	4,332	3½-4½
2010							850[a]	841	821	799	4,955	2½-3½
2011								960[a]	949	923	5,719	1½-2½
2012									1,080[a]	1,069	6,579	½-1½
2013										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= \$750,000
Exposures at age ½	= \$750,000 - \$ 8,000	= \$742,000
Exposures at age 1½	= \$742,000 - \$18,000	= \$724,000
Exposures at age 2½	= \$724,000 - \$20,000 - \$19,000	= \$685,000
Exposures at age 3½	= \$685,000 - \$22,000	= \$663,000

For the entire experience band 2001-2010, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page**,** is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2004-2013 Placement Band 1999-2013

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

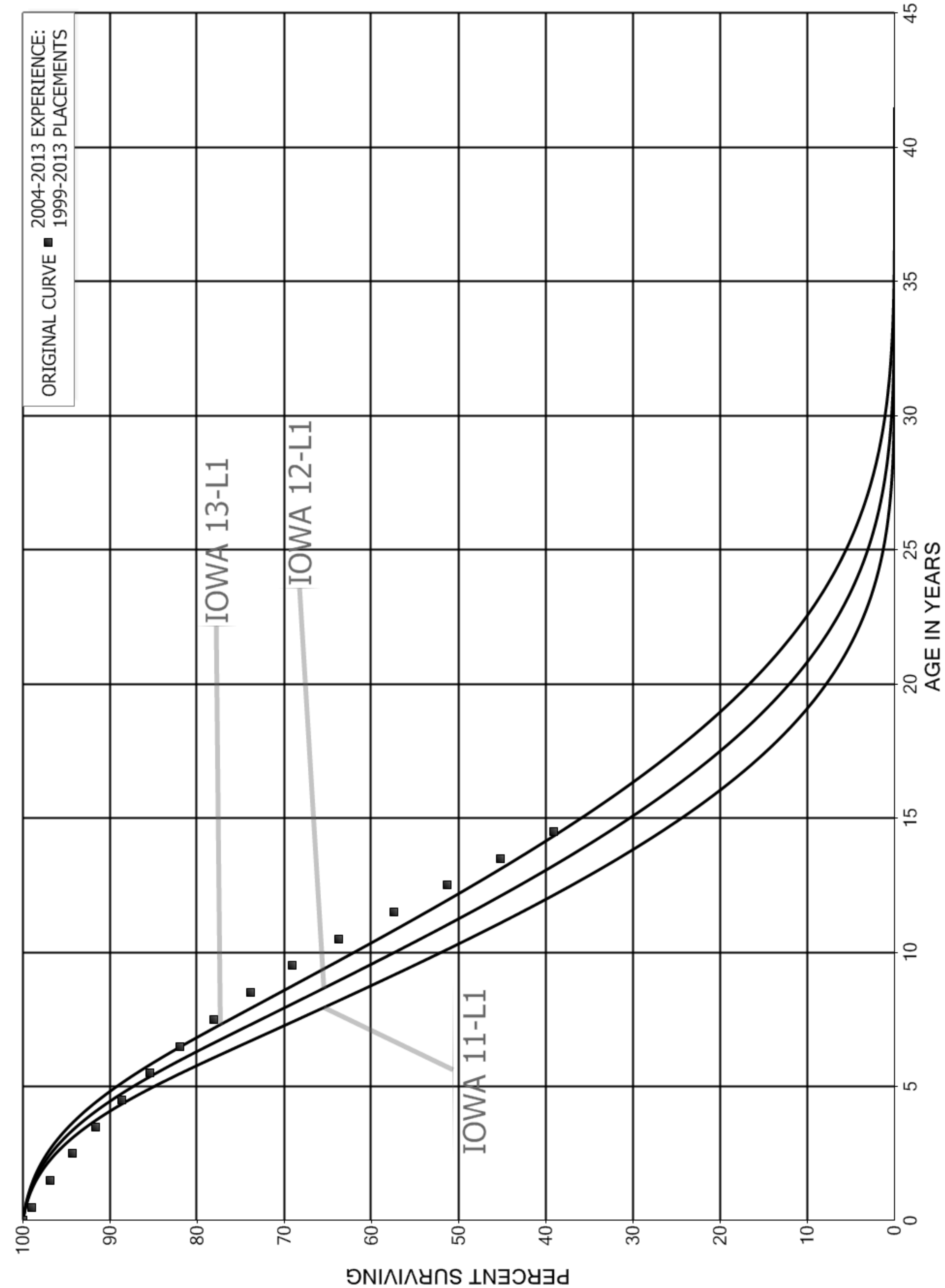


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

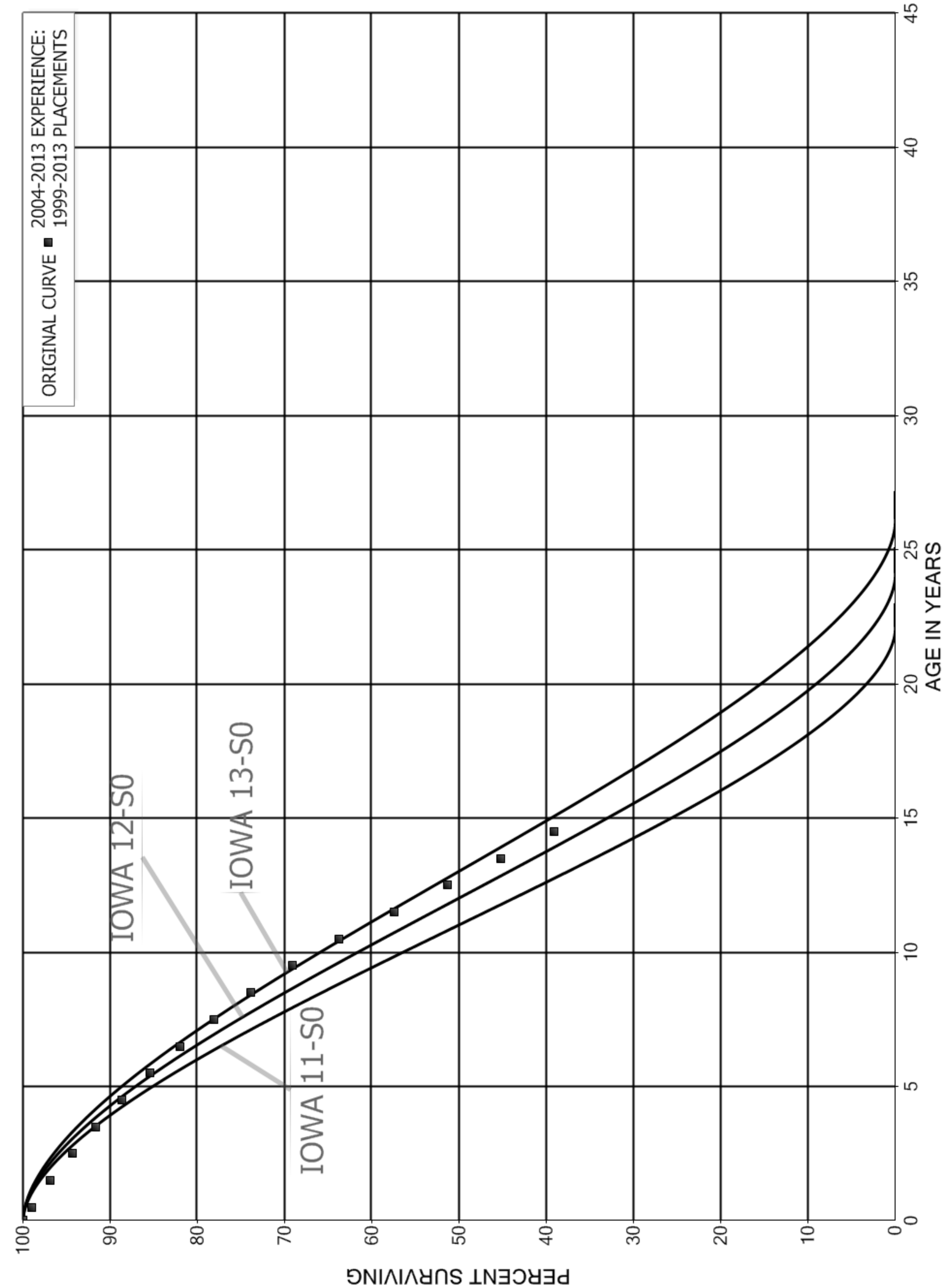


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

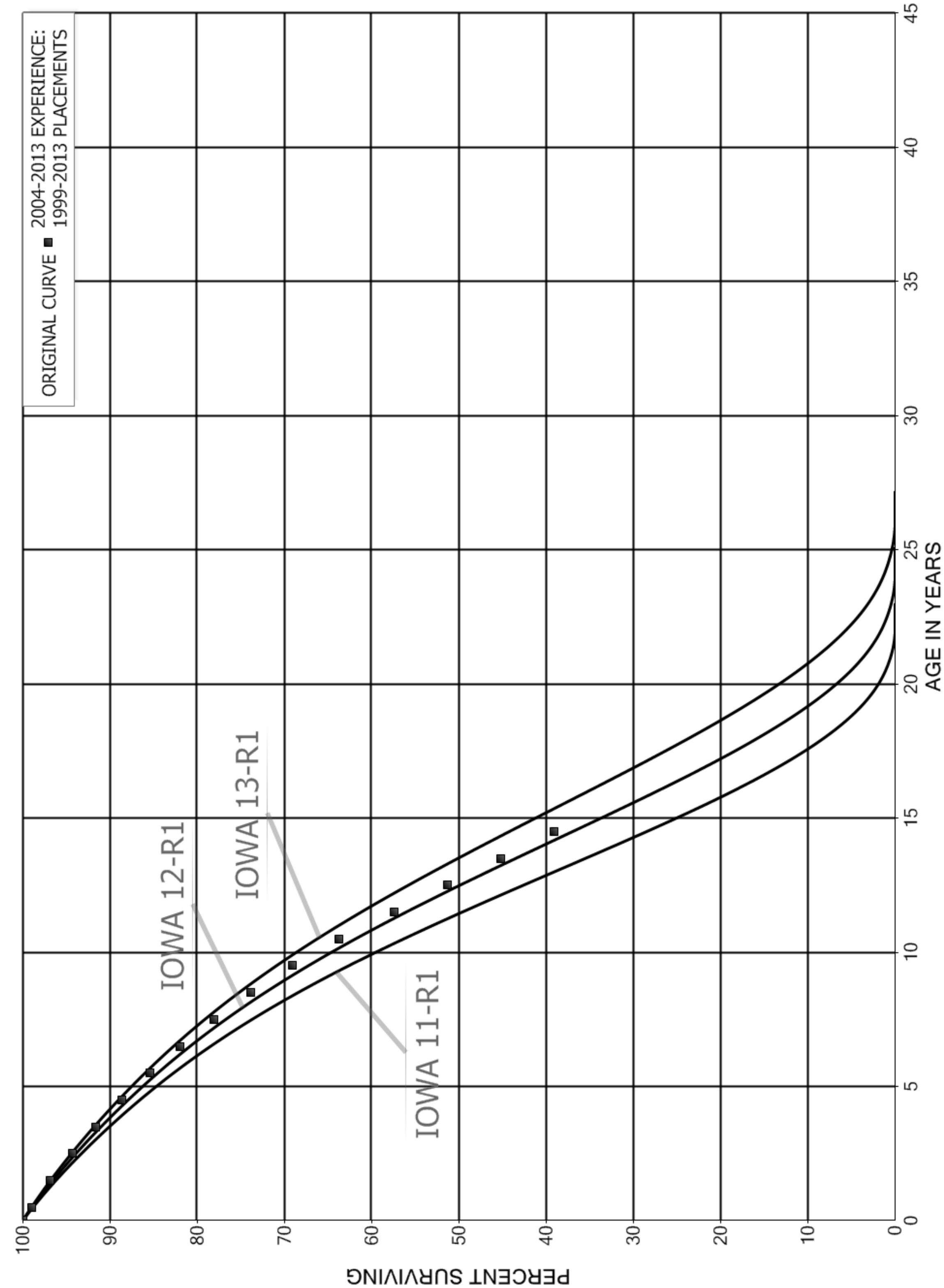
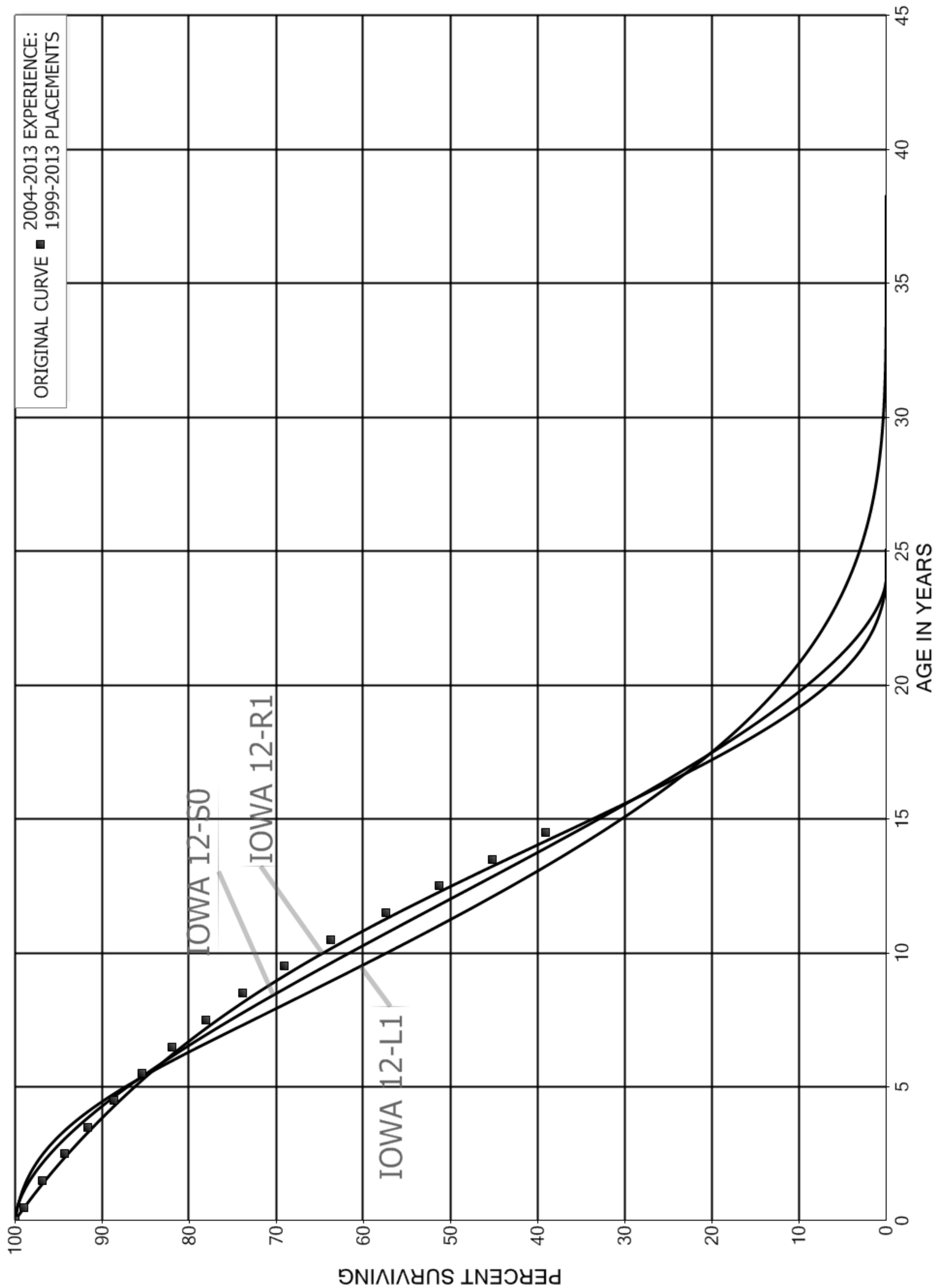


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



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MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

APPENDIX 5.7
ACCOUNTING POLICY & ESTIMATE CHANGES

1.0 ACCOUNTING POLICY & ESTIMATE CHANGES

In Order 43/13, the PUB accepted the accounting policy changes that have been made by Manitoba Hydro to 2013/14 for the purposes of rate setting but indicated that until an IFRS Status Update Report is filed at the next GRA, no further changes should be made for rate-setting purposes.

> *"The Board understands that Manitoba Hydro has been making changes to its accounting policies since 2007/08 to be more consistent with other electric utilities as well as to be consistent with International Financial Reporting Standards. The Board in past orders had expressed concern with the level of capitalization and Manitoba Hydro has begun to address these concerns. In the Board's view, Manitoba Hydro's proposed accounting changes are appropriate for the test years. The Board will direct Manitoba Hydro to file an International Financial Reporting Standards status update at the next General Rate Application. Until such time, the Board expects Manitoba Hydro not to make any further accounting changes for rate-setting purposes."* (Order 43/13, pages 14-15)

> *"The Board accepts the depreciation rates applied April 1, 2011, which rates reflect the changes in service lives and the true-up of the accumulated depreciation surplus for the two test years. The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial Reporting Standards are implemented rather than during the test years."*(Order 43/13, page 18)

There are a number of prospective accounting changes that Manitoba Hydro is making for financial reporting purposes in 2014/15 and 2015/16. The most significant of these include the implementation of a comprehensive depreciation study in 2014/15 and further changes to the level of capitalized overhead and deprecation methodologies as part of the implementation of IFRS in 2015/16. These changes are discussed in the following sections.

2.0 DEPRECIATION STUDY 2014/15

Manitoba Hydro recently completed a new depreciation study in October 2014, which developed new Canadian GAAP (CGAAP) and IFRS compliant depreciation rates. In 2014/15, the Corporation will be implementing new CGAAP depreciation rates that reflect the extension of services lives of certain asset groups, which reduces annual depreciation expense. As outlined in Appendix 5.7 this change in accounting estimate of the asset service lives results in a reduction in depreciation expense of $25 million in 2014/15, $29 million in 2015/16, and $30 million in 2016/17.

3.0 IFRS IMPLEMENTATION 2015/16

Manitoba Hydro will be transitioning to IFRS effective April 1, 2015 for its 2015/16 fiscal year with comparative information presented for 2014/15. In addition, Manitoba Hydro will early adopt interim standard IFRS 14 Regulatory Deferral Accounts upon transition. This interim standard allows Manitoba Hydro to continue to recognize regulated assets and liabilities. This standard will provide temporary guidance until the IASB completes its comprehensive project on Rate-regulated accounting, which is expected to take several years to complete. MH14 assumes that regulatory deferral accounts will continue to be recognized throughout the 20 year forecast period. Please see Appendix 5.4 for the IFRS Status Update Report.

Generally speaking, the transition to IFRS will result in timing differences between when expenditures are recognized into income between Canadian Generally Accepted Accounting Principles (CGAAP) and IFRS. Manitoba Hydro recognizes that the different financial reporting requirements under IFRS will both increase and decrease annual net income. As such, Manitoba Hydro has considered the range of potential impacts and where possible, has selected accounting policies aimed at minimizing the overall impact to financial results and revenue requirements.

The primary impacts of IFRS accounting policy changes that are included in MH14 are as follows:

- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred (please see Appendix 5.5 for more information);
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates (please see Appendix 5.7 for more information and the results of the 2014 electric depreciation study); and,
- Unamortized experience gains and losses on pension balances will be reclassified to accumulated other comprehensive income (AOCI) upon transition to IFRS.

3.0 TOTAL IMPACT OF ACCOUNTING POLICY AND ESTIMATE CHANGES

As summarized in the table below, the overall impacts of the accounting policy and estimate changes that are forecast to be made in 2014/15 and 2015/16 offset each other and result in an overall reduction in Manitoba Hydro's future revenue requirements. The significance of the net changes are minimal in the 2015 to 2017 period, and as such are not driving the need for the proposed rate increases.

Figure 5.6.1: Accounting Policy & Estimate Changes

Accounting Policy & Estimate Changes Electric operations (in millions of $s)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OM&A Expense Changes		51	56	57	58	58	59	60	61	62
Depreciation Expense Changes	(25)	(53)	(57)	(60)	(76)	(86)	(96)	(101)	(103)	(105)
Other		(3)	(3)	(4)	(3)	(3)	(4)	(4)	(3)	(4)
Total Increase (Decrease) in Revenue Requirement	(25)	(4)	(4)	(7)	(22)	(31)	(41)	(45)	(46)	(48)

Given the offsetting nature of the various IFRS accounting changes and the depreciation estimate change as noted in the figure above, as well as the adoption of the interim standard IFRS 14 Regulatory Deferral Accounts, the use of IFRS financial reporting policies for rate-setting purposes is appropriate as there is no negative impact to ratepayers.

The following schedules provide additional detail with respect to the accounting policy and estimate changes in MH14.

SCHEDULE A - ACCOUNTING POLICY & ESTIMATE CHANGES - IFF14

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Ref
Electric only (in millions of $'s)											
OM&A											
Administrative Overhead		55	55	56	56	57	57	58	59	60	**1**
Meter Compliance, Exchange and Sampling		(1)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	**2**
Pension		0	3	3	3	3	3	3	4	4	**3**
Employee Benefits		(2)	(0)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	**4**
Subtotal OM&A Changes		**51**	**56**	**57**	**58**	**58**	**59**	**60**	**61**	**62**	
DEPRECIATION EXPENSE											
Average Service Life Changes (2014 Depreciation Study)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)	**5**
Administrative Overhead		(0)	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)	**1**
Meter Compliance, Exchange and Sampling		0	0	0	0	0	0	1	1	1	**2**
Removal of Net Salvage		(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)	**6**
Change to IFRS Compliant Depreciation		36	38	41	49	55	63	67	68	69	**7**
Subtotal Depreciation Changes	**(25)**	**(53)**	**(57)**	**(60)**	**(76)**	**(86)**	**(96)**	**(101)**	**(103)**	**(105)**	
FINANCE EXPENSE											
Total Finance Expense Accounting Changes		(0)	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)	**8**
CAPITAL TAX EXPENSE											
Total Capital Tax Expense Accounting Changes		(3)	(3)	(3)	(2)	(2)	(2)	(2)	(1)	(1)	**8**
Total Increase (Decrease) in Revenue Requirement	**(25)**	**(4)**	**(4)**	**(7)**	**(22)**	**(31)**	**(41)**	**(45)**	**(46)**	**(48)**	

SCHEDULE B - ACCOUNTING POLICY & ESTIMATE CHANGES - IMPACT TO RETAINED EARNINGS & ACCUMULATED OTHER COMPREHENSIVE INCOME- IFF14

Electric only (in millions of $'s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
IMPACT TO RETAINED EARNINGS											
Annual change to OM&A	-	(51)	(56)	(57)	(58)	(58)	(59)	(60)	(61)	(62)	(521)
Annual change to Depreciation & Amortization	25	53	57	60	76	86	96	101	103	105	763
Annual change to Finance & Capital Tax Changes	-	3	3	3	3	3	4	4	4	5	(16)
Write Offs to:											
Administrative Overhead		(54)									(54)
Provision for Asset Removal		57									57
Change to Equal Life Group Depreciation		(33)									(33)
Pension & Employee Benefits		(24)									(24)
Total (Decrease) Increase to Retained Earnings	**25**	**(50)**	**4**	**7**	**22**	**31**	**41**	**45**	**46**	**48**	**171**
IMPACT TO AOCI											
IFRS Changes											
Pension Adjustment to AOCI		(445)	-	-	-	-	-	-	-	-	(445)
Pension Adjustment for discount rate changes		-	-	61	40	40	-	-	-	-	141
Total Annual Impact to AOCI	**-**	**(445)**	**-**	**61**	**40**	**40**	**-**	**-**	**-**	**-**	**(304)**

Reference	Description	Accounting Handbook Reference
1	The reduction in administrative and general overhead capitalized reflects adjustments to comply with IFRS upon transition. IFRS does not permit the capitalization of general administrative and overhead costs. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	**IFRS - IAS 16 Property, plant & equipment:** .19 Examples of costs that are not costs of an item of property, plant and equipment are:,… (d) administration and other general overhead costs.
2	IFRS requires uniform accounting policies to be applied to all entities in a consolidated group. Manitoba Hydro will be harmonizing its accounting policy with respect to costs associated with its Meter Sampling, Exchange and Testing program.	**IFRS 10 Consolidated Financial Statements** 19 A parent shall prepare consolidated financial statements using uniform accounting policies for like transactions and other events in similar circumstances. Uniform accounting policies: B87 If a member of the group uses accounting policies other than those adopted in the consolidated financial statements for like transactions and events in similar circumstances appropriate adjustments are made to that group member's financial statements in preparing the consolidated financial statements to ensure conformity with the group's accounting policies.
3	Overall, changes to the accounting for pension and benefits results in an increase in pension and benefit costs upon transition to IFRS. The primary pension accounting changes include: • upon transition, unamortized pension gains and losses will be adjusted to accumulated other comprehensive income; • the elimination of "corridor" determined amortization for unrealized pension experience gains and losses as IFRS requires annual gains and losses to be recognized in Other Comprehensive Income; and • the use of the pension discount rate for recording expected returns on plan assets as opposed to the expected market interest rate of return as per CGAAP.	**IFRS – IAS 19 Employee Benefits:** .120 An entity shall recognize the components of defined benefit cost, except to the extent that another IFRS requires or permits their inclusion in the cost of an asset, as follows: (a) service cost in profit or loss;…, (c) re-measurements of the net defined benefit liability (asset) in other comprehensive income. .125 Interest income on plan assets is a component of the return on plan assets, and is determined by multiplying the fair value of the plan assets by the discount rate specified in paragraph 83, both as determined at the start of the annual reporting period, taking account of any changes in the plan assets held during the period as a result of contributions and benefit payments. .103 An entity shall recognize past service cost as an expense at the earlier of

		the following dates: (a) when the plan amendment or curtailment occurs; and (b) when the entity recognizes related restructuring costs or termination benefits (see paragraph 165).
Reference	**Description**	**Accounting Handbook Reference**
4	**Employee benefits:** The primary employee benefit related changes include: • upon transition, unamortized past service adjustments will be adjusted to retained earnings; and • future annual benefits expense will be higher for the recognition of benefits attributed to unvested employees for benefits such as sick leave and severance. Such unvested benefits were not recognized under CGAAP, but are required to be recognized under IFRS.	**Employee Benefits:** .15 Accumulating paid absences are those that are carried forward and can be used in future periods if the current period's entitlement is not used in full. ,…, An obligation arises as employees render service that increases their entitlement to future paid absences. The obligation exists, and is recognized, even if the paid absences are non-vesting, although the possibility that employees may leave before they use an accumulated non-vesting entitlement affects the measurement of that obligation.
5	The net result of the 2014 depreciation study and the average service life approach is an overall reduction in annual depreciation expense for MH due to changes in the service lives for certain asset groups. This change is required to be implemented under Canadian GAAP.	**CGAAP – 3061 Property, plant & equipment:** .28 Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise. .33 The amortization method and estimates of the life and useful life of an item of property, plant and equipment should be reviewed on a regular basis. [DEC. 1990 *****]
6	Upon adoption of IFRS, MH will be removing the impact of net salvage from depreciation rates.	-The Inclusion of net salvage in depreciation rates is a regulatory practice applied under CGAAP by Canadian utilities. Manitoba Hydro will be removing negative salvage from depreciation rates in order to manage the other accounting changes and minimize overall impacts to revenue requirement.
7	In order to satisfy the componentization requirements of IFRS, MH will be moving from the Average Service Life method of depreciation to the Equal Life Group method upon its adoption of IFRS.	**IFRS - IAS 16 Property, plant & equipment:** The key IFRS references supporting the move to the ELG method are: .43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

		.68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit or loss when the item is de-recognized. Gains shall not be classified as revenue.
8	The changes to finance expense and capital and other taxes reflect the cumulative impacts of changes 1 – 7 as identified in this chart.	**Please see descriptions as provided in 1- 7.**

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SCHEDULE C - ACCOUNTING POLICY & ESTIMATE CHANGES - IMPACT ON IFF14

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
IMPACT OF ACCOUNTING POLICY & ESTIMATE CHANGES
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	-	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	-	-	-	-	-
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 351	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	491	496	500	513	527	542	547	558	569
Accounting Changes:	-	51	56	57	58	58	59	60	61	62
Finance Expense	495	510	548	582	753	888	1 196	1 327	1 336	1 352
Accounting Changes:	-	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)
Depreciation and Amortization	430	454	480	505	597	610	708	768	840	857
Accounting Changes:	(25)	(53)	(57)	(60)	(76)	(86)	(96)	(101)	(103)	(105)
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	110	123	137	146	146	146	152	152	162
Accounting Changes:	-	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(1)	(1)
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 956	2 044	2 317	2 471	2 920	3 150	3 239	3 304
Non-controlling Interest	(25)	(12)	(8)	(7)	(5)	(4)	(10)	(0)	1	3
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

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MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

PROPOSED RATES AND CUSTOMER IMPACTS

INDEX

Appendices

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

PROPOSED RATES AND CUSTOMER IMPACTS

6.0 OVERVIEW

Tab 6 provides the proposed rates and customer impacts for the proposed rate changes in this Application. Section 6.1 provides Manitoba Hydro's general rate making objectives; Section 6.2 provides details of the proposed rates by customer class and the customer bill impacts of the proposed rate changes; Section 6.3 describes the proposed implementation of Time-of-Use ("TOU") Rates effective April 1, 2016 for the General Service Large Customer Class served at greater than 30 kV; Section 6.4 outlines proposed changes and approvals requested with respect to the Surplus Energy Program ("SEP") and the Curtailable Rates Program ("CRP"). Section 6.5 discusses Manitoba Hydro's current review of its Cost of Service Study and the related Stakeholder Engagement process that has been undertaken. Section 6.6 provides a comparison of electricity rates across other jurisdictions and provides context to the rate pressures experienced in general in the Canadian electric utility industry.

The key observations of Tab 6 are:

1. Manitoba Hydro has applied the proposed 3.95% rate increases to all components of the rates (monthly basic charges, energy charges and demand charges) on an across-the-board basis for all customer classes, sufficient to generate additional revenue of $57.4 million for fiscal 2015/16, and $59.9 million for fiscal 2016/17.

2. Manitoba Hydro is requesting approval to implement TOU rates for customers in the General Service Large customer classes served at greater than 30 kV, effective April 1, 2016. The introduction of a TOU rate enables Manitoba Hydro to provide more appropriate price signals to large energy users that is more reflective of the value of energy in the on-peak period.

3. Manitoba Hydro is seeking confirmation that the PUB accepts the rates flowing from the changes to the terms and conditions of the SEP and CRP programs that were approved on an interim basis in Order 43/13.

4. Manitoba Hydro has undertaken a stakeholder engagement process to facilitate the sharing of views and alternatives to Cost of Service Study ("COSS") methodology to identify possible alternative treatments for the assumptions in the methodology. The Corporation will continue its examination of its COSS with a goal of advancing its next COSS for public review at an appropriate time that will be determined in conjunction with the PUB and stakeholders.

5. The issue of aging infrastructure is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the proposed and indicative rate increases in MH14, it is expected that Manitoba's domestic electricity customers will continue to have rates that are affordable and competitive with other utilities in North America.

6.1 <u>RATE OBJECTIVES</u>

Manitoba Hydro's general rate making objectives are set out as follows:

1. Manitoba Hydro's long-term target is to have all class Revenue Cost Coverage (RCC) ratios in the range of 95% to 105%, and further that all classes should be gradually moved toward RCC's of unity.

2. In conformity with the principles of gradualism and sensitivity to customer impacts, annual adjustments to revenues by customer class are less than two percentage points greater than the overall proposed increase.

3. Whenever possible, rates should be designed with a view to sending the appropriate price signal regarding the cost of energy to those parts of the rate design affecting the use which would be most sensitive to such a signal.

4. Maintain Manitoba Hydro's competitive position with respect to rates charged by other Canadian utilities for all rate classes.

5. The combined impact of proposed class average rate increases and adjustments to rate structure results in customer monthly impacts which fall within Manitoba Hydro's guidelines:

– For Residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.

– For General Service customer, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.

6.2 PROPOSED RATE CHANGES & CUSTOMER IMPACTS BY CLASS

The following sections discuss the proposed rate schedules and customer impacts. A Proof of Revenue for each fiscal year (2015/16 and 2016/17) detailing the total revenue increase by customer class is provided in Appendices 6.1 and 6.2. Rate Schedules for proposed rates effective April 1, 2015 and April 1, 2016 are provided in Appendices 6.3 and 6.4, respectively. Appendices 6.5 and 6.6 provide Bill Comparisons between current May 1, 2014 rates, proposed April 1, 2015 rates and proposed April 1, 2016 rates.

On a class basis, the increase in revenues is shown in the following figure:

Figure 6.1 Recovery of Additional Revenues By Customer Sub-Class

Customer Class	2015/16 Additional $(millions)	2016/17 Additional $(millions)
Residential	$23.8	$25.2
GS Small*	$11.6	$12.3
GS Medium	$8.0	$8.5
GS Large	$13.8	$14.4
A&R Lighting	$0.9	$0.9
Misc. & DSM	($0.7)	($1.4)
Total GCR	$57.4	$59.9

*includes revenues from General Service customers in Diesel Communities

6.2.1 Residential

The proposed 3.95% increase applied to the current rates for the residential class would result in a monthly Basic Charge of $7.57 and an Energy Charge of $0.07672 per kWh for rates effective April 1, 2015. For the following fiscal year, the proposed 3.95% increase would result in a Basic Charge of $7.87 and an Energy Charge of $0.07975 per kWh for rates effective April 1, 2016.

A residential customer, without electric space heat, with an average usage of 1,000 kWh per month would experience an increase in their monthly bill of $3.20 for 2015/16 and $3.33 for 2016/17. A residential customer with electric space heat, using an average of 2,000 kWh a month, would experience increases of $6.11 and $6.36 per month for April 1, 2015 and April 1, 2016, respectively.

6.2.2 General Service Small and Medium

Manitoba Hydro is proposing to apply the 3.95% rate increase across all rate components in the General Service Small and Medium rate sub-classes.

Prior to the 2012/13 & 2013/14 General Rate Application, Manitoba Hydro was gradually adjusting the application of rate increases to eventually achieve the consolidation of the General Service ("GS") Small and Medium rate classes. At the present time, the rates for these two classes vary only with respect to the monthly Basic Charge and Three Phase Charge. As the proposed rate increases are to be applied to all rate components, including Basic Charges and Three Phase Charges, no additional consolidation of these rate classes will result with this Application.

A 3.95% increase on April 1, 2015 would result in the Basic Charge increasing to $20.51 for the GS Small Single Phase and $28.92 for the GS Small Three Phase. It is proposed that on April 1, 2016 these charges will increase to $21.32 and $30.06 respectively. The Basic Charge for the GS Medium class is proposed to increase to $30.52 on April 1, 2015 and to $31.73 on April 1, 2016. All components of the Energy Charge are proposed to increase by 3.95% each of the fiscal years as shown below:

Figure 6.2 Energy Charges for General Service Small and Medium

	April 1, 2015	April 1, 2016
1st 11,000 kWh @	$0.08058 / kWh	$0.08376 / kWh
Next 8,500 kWh @	$0.05594	$0.05815
Balance of kWh	$0.03692	$0.03838

In keeping with the past application of these demand charges, the first 50 kV.A of Billing Demand each month will not be charged, but for demand in excess of 50 kV.A the rate is proposed to increase 3.95% to $9.45 on April 1, 2015 and to $9.82 on April 1, 2016.

6.2.3 General Service Diesel Rates

Manitoba Hydro is proposing to apply the 3.95% increases to both the grid portion of the rate structure (equal to that proposed for grid customers) and the non-grid portion of the rate applicable to general service and government customers in the four remote communities served by diesel generation (Shamattawa, Brochet, Lac Brochet and Tadoule Lake). For General Service non-government customers, the first 2,000 kWh per month will be the same as the grid-rate equivalent as the General Service Small and Medium customer class first block rate. Energy usage in excess of 2,000 kWh per month is proposed to increase by 3.95% in 2015 to $0.41232 per kWh, and increase an additional 3.95% in 2016 to $0.42861 per kWh. For General Service government customers, including First Nation Education accounts, all energy is proposed to be charged at the rate of $2.5095 for rates effective April 1, 2015 and $2.6086 for rates effective April 1, 2016.

6.2.4 General Service Large

This Application seeks a 3.95% increase to both the Energy Charge and Demand Charge for the General Service Large sub-classes to be effective on April 1, 2015.

The present standard rate design, comprised of a single Energy Charge and a single Demand Charge, is proposed for rates effective April 1, 2015 for all three sub-classes of the General Service Large class. In this Application, both the Energy Charge and Demand Charge for all three General Service Large sub-classes is proposed to increase by 3.95% on April 1, 2015:

- The Large 750V-30 kV sub-class would have an Energy Charge of $0.03472 per kWh and a Demand Charge of $8.02 per kV.A.
- The Large 30-100 kV sub-class would have an Energy Charge of $0.03228 per kWh and Demand Charge of $6.87 per kV.A.
- The Large >100 kV sub-class would have an Energy Charge of $0.03128 per kWh and Demand Charge of $6.11 per kV.A.

For rates effective April 1, 2016, rates for the General Service Large 750V-30 kV sub-class would increase an additional 3.95% resulting in an Energy Charge of $0.03609 and a Demand Charge of $8.34 per kV.A. This would result in bill increases averaging 3.95% depending on load factor.

For customers in the GSL 30-100 kV and GSL > 100 kV sub-classes, Manitoba Hydro is proposing to introduce a Time-of-Use ("TOU") rate design effective April 1, 2016. Please see Section 6.3 on TOU rates for information on the derivation and level of rates for GSL 30 – 100 kV and GSL > 100 kV customer sub-classes.

The bill impacts provided in Appendix 6.6 for the GSL 30-100 and GSL > 100 sub-classes provide two sets of comparisons. The first compares the proposed April 1, 2015 rates to the proposed April 1, 2016 TOU rates. This comparison produces an aggregate view of the bill impacts which includes both the 3.95% general rate increase as well as the impact of the change from the current rate design to the TOU rate design. In order to isolate the bill impact of the rate design change alone, a second set of bill impacts is provided which compares the proxy rates under the current rate design for April 1, 2016 versus the proposed TOU rates. This comparison presents the impact of the introduction of the TOU rate design exclusive of the 3.95% rate increase.

The TOU rates proposed for April 1, 2016 also include a proposal to increase the demand ratchets for the Large >30 kV customers from 25% to 50% of contract demand or 50% of the highest recorded demand in the past 12 months. Please refer to Section 6.3 for a more detailed explanation of this proposed change to the demand ratchets.

6.2.5 Area and Roadway Lighting

Manitoba Hydro is proposing to apply the 3.95% rate increase to the Area and Roadway Lighting class for each of the two fiscal years. In addition, Manitoba Hydro is seeking approval of rates for street lighting using new Light Emitting Diode ("LED") technology. In addition to the LED rate categories approved on an interim basis in Order 79/14, Manitoba Hydro is proposing additional new LED rate categories to address the additional street lighting sizes and wattages, as found on page 21 of Appendix 6.3 and page 22 of Appendix 6.4. Please see Appendix 6.13 for Manitoba Hydro's letter of June 23, 2014, requesting PUB approval to implement LED Rates.

6.2.6 Limited Use of Billing Demand ("LUBD") Rate Option

The rates proposed for LUBD customers are derived from the rates proposed for General Service Small, Medium and Large customer classes. The monthly Basic Charge will increase to the same level as regular GS Small/Medium customers. The Demand Charge is set at approximately 25% of the Demand Charge of the corresponding regular General

Service class, with the energy charge calculated to provide revenue neutrality at a load factor of approximately 18%.

A copy of the latest LUBD report filed with the PUB, covering the period April 1, 2013 to March 31, 2014, is included as Appendix 6.12.

6.2.7 Flat Rate Water Heating ("FRWH")

Manitoba Hydro proposes to apply the 3.95% rate increase to the rate components for both Residential and General Service FRWH customers. There are approximately 3,600 Residential FRWH customers and approximately 370 General Service FRWH customers, and the number of customers on FRWH has been declining by approximately 5% per year.

6.3 TIME-OF-USE RATES FOR GENERAL SERVICE LARGE

Manitoba Hydro is requesting approval to implement TOU rates for customers served in the GSL 30-100 kV and GSL > 100 kV sub-classes, effective April 1, 2016. The proposed TOU rates shown in the April 1, 2016 rate schedules have been designed to recover the same level of revenue (revenue neutral) that would have been recovered through the present standard rate design.

The introduction of a TOU rate enables Manitoba Hydro to provide more appropriate price signals to large energy users and to provide a clear indication of the value of energy to Manitoba Hydro. It also provides industrial customers with a rate design that will incent customers to optimize their energy usage and facilitates opportunities for managing their energy bills. This rate design further assists Manitoba Hydro in addressing concerns about load growth by energy-intensive industries and the potential impact that such growth may have with regard to on-peak export sales.

6.3.1 Background to the TOU Proposal

The issue of industrial rate design was last examined in the public hearing process for Manitoba Hydro's Energy Intensive Industrial Rate ("EIIR") Application in December 2008. Concerns about specific aspects of that rate design lead to Manitoba Hydro advancing a revised EIIR proposal in February 2010. However, it became apparent to the Corporation that the EIIR concept still had shortcomings. In October 2010, Manitoba Hydro withdrew its request for implementation of the EIIR and embarked on an engagement process with the Manitoba Industrial Power Users Group ("MIPUG") to develop a more acceptable solution.

Manitoba Hydro consulted with members and representatives of MIPUG between 2010 and 2012 with an objective to develop a mutually acceptable form of rate design that would consider the needs of both Manitoba Hydro and the industrial customers. A TOU rate concept emerged from those discussions as being a reasonable and acceptable approach to rate design for large electrical consumers in Manitoba. The TOU rate design is uniformly applicable to all existing and expanding loads served at 30 kV and over, and is simpler and easier to administer by abandoning the use of complex and controversial baseline calculations and growth allowances.

In order to advance the TOU rate design proposal, in the spring and summer of 2012, Manitoba Hydro held several stakeholder information sessions. Three sessions were conducted, with Winnipeg and rural area large energy users and with registered intervenors, in order to share information on the proposal with interested and affected parties. In September, 2012, the MHEB approved the request to advance the TOU rate design proposal before the PUB in the 2012/13 & 2013/14 General Rate Application. Shortly thereafter, the PUB determined that it would be more appropriate to address the topic of TOU rate design at a later date and deferred its review of the proposal to a future public hearing process.

Manitoba Hydro is of the view that it is appropriate to advance a proposal for TOU rate design in this General Rate Application, and if approved, implement the proposal as of April 1, 2016. The Corporation notes the extensive discussion and engagement with MIPUG and affected GSL customers in the 2010-2012 time frame in the formulation and development of the TOU rate proposal. The features of that original TOU proposal are intact and have been brought forward in the current rate design proposal. The level of the various energy and demand charges have been re-calculated to reflect current revenue requirements and certain adjustments have been made to mitigate the level of billing impact on customers at the transition to the new rate design.

Manitoba Hydro intends to assist customers in transitioning to a new rate design by providing technical and analytical support to identify the resulting cost impacts and reductions available to customers under the proposed changes. Such support may include energy usage analysis and assistance in examining appropriate contract demand levels for optimal effectiveness and control of energy costs.

6.3.2 Features of the TOU Rate Design

The proposed TOU rate design features differentiated energy rates for on-peak and off-peak energy consumption and a single demand charge based upon the maximum demand set during the on-peak period. The resulting energy rates are higher during the on-peak periods (Monday to Friday from 6:00 a.m. to 10:00 p.m. excluding Statutory holidays) and lower during the off-peak periods (all other hours) in comparison to the single block energy charges that are characteristic of the present standard rate design. Energy rates for on-peak periods are further differentiated between winter (December to March inclusive) and all other or "non-winter" months.

In order to design an appropriate on-peak energy price signal while at the same time maintaining revenue neutrality for the rate class, the following issues were considered.

- The relationship to average MISO market pricing was considered in order to reflect marginal cost considerations in the establishment of the appropriate rate level.
- The level of on-peak energy rates was considered and set to be more reflective of on-peak export market pricing typical of firm sales arrangements than would otherwise be possible through the present standard rate design.
- The level of rate differentiation between on-peak and off-peak energy was considered in order to provide sufficient price differentiation to encourage customer response.
- The balance between recovery through energy charges and demand charges was considered primarily to address bill impacts and customer receptiveness to the introduction of a new rate design.

Each of these factors is taken into consideration in the determination of the level of the on-peak and off-peak energy price and the relative amount of revenue to be recovered between energy charges and demand charges.

The relationship of on-peak and off-peak pricing was examined with consideration for the long-term relationship of on and off peak prices in the day-ahead MISO market experienced at the MHEB node. An examination of the ten year average of MISO day-ahead prices indicates the ratio of on-peak to off-peak prices is approximately 1.8. In other words, on-peak prices, on average, were 1.8 times higher than the off-peak price over the ten year period.

This relationship was used to establish the differentiation between the on-peak (non-winter) price and the off-peak price. On-peak prices for the winter season were then set at a level approximately one cent per kWh higher than the non-winter seasonal rate, which is intended to recognize a higher value of capacity during the winter season, recognizing that Manitoba Hydro is a winter peaking utility and that capacity in the winter months has more value.

6.3.3 Calculation of the TOU rate proposed for April 1, 2016

In order to calculate TOU rates for April 1, 2016, a set of proxy 2016 rates were calculated that conform to the present standard rate design. The TOU rates (as shown in Appendix 6.4) are based on revenue neutrality to the present standard rate design. The proxy rates were created by applying the 3.95% rate increase for April 1, 2016 to the proposed April 1, 2015 rates. This results in the following proxy rates:

- Large >100 kV sub-class would have an Energy Charge of $0.03252 per kWh and Demand Charge of $6.35 per kV.A.
- Large 30-100 kV sub-class would have an Energy Charge of $0.03356 per kWh and Demand Charge of $7.14 per kV.A.

With consideration of the energy rate setting factors discussed in the above section, and based upon the level of revenues proposed to be recovered in fiscal year 2016, the energy and demand rates were calculated for GSL 30-100 kV and GSL > 100 kV subclasses. The resulting proposed on-peak and off-peak energy rates for those sub-classes are shown in the following table:

Figure 6.3 Proposed On-Peak and Off-Peak Energy Rates General Service Large Customers

	Large >100kV	Large 30-100kV
On-peak (winter)	$0.0570	$0.0590
On-peak (non-winter)	$0.0470	$0.0486
Off-peak (all)	$0.0260	$0.0270

In order for the TOU rates to be revenue-neutral compared to the present rate structure, the proposed demand charges have been reduced by 35% to 45% relative to the standard rate design demand charges. This adjustment in the recovery between demand and energy charges is also useful in mitigating the initial bill impact to customers transitioning to the TOU rate design.

Consequently, the TOU Demand Charge has been set at approximately 55% of the $6.35 shown above for the Large >100 kV class or $3.50; and 65% of the $7.14 for the Large 30-100 kV class or $4.64.

6.3.4 Proposed Changes to Demand Ratchet Levels

In addition to the proposed implementation of TOU rates, Manitoba Hydro proposes to change the level of the ratchet used to determine the GSL 30-100kV and GSL>100kV sub-class minimum billing demand. Manitoba Hydro is proposing to change the definition of billing demand for these sub-classes to be the greatest of (in kVA):

- The highest measured on-peak demand in the month; or
- 50% of the contract demand; or,
- 50% of the highest on-peak demand in the previous 12 months.

The intent of raising the ratchet levels is to encourage customers to make efficient use of the transmission and sub-transmission system that is built to serve them.

Manitoba Hydro is contractually obligated to provide power up to the level of each customer's contract demand. In some cases, a customer's contract demand level may be significantly more than the actual peak demand experienced by that customer. Historically, there has not been a significant cost for a customer to contract for more capacity than required, as the 25% contract demand ratchet is relatively low.

Manitoba Hydro is concerned that unused capacity, reserved by customers through their specified contract demand levels, may limit the Corporation's ability to serve new and/or expanding load with existing transmission infrastructure, resulting in potential costs for new infrastructure that would not be required if unused capacity was released. Manitoba Hydro's current General Service Large rate structure includes a minimum monthly billing demand charge that is defined as the highest of actual recorded demand, 25% of contract demand or 25% of the highest recorded demand in the past 12 months. The existing billing threshold provides minimal incentive for most large customers to reduce their contracted demand levels if significant contracted capacity remains unused.

6.3.5 Changes to GSL>30kV Rate Design and Bill Impacts

While the TOU rate is designed to be revenue neutral from a customer class perspective, it is recognized that the introduction of a new rate design will result in a range of customer impacts within the GSL 30-100 kV and GSL > 100 kV sub-classes, due to the difference in hourly energy consumption patterns between customers in the same sub-class. Within each sub-class, some customers that will experience lower annual bills and others will experience higher annual bills compared to the present rate design, which is directly related to each individual customer's energy usage pattern. Manitoba Hydro has taken measures to address the billing impacts of transitioning to a new rate design, as set out below.

The proposed change to the demand ratchet level will have a billing impact on a small number of customers that are currently operating at demand levels that are significantly lower than their contracted demand. Manitoba Hydro is addressing those impacts by offering to re-contract those customers at lower demand levels that are more aligned with their current operating characteristics.

The TOU rate proposal filed with the 2012/13 & 2013/14 General Rate Application resulted in higher bill impacts to a small number of customers in the GSL 30-100 sub-class, due to the pattern of their energy usage. Those impacts have been mitigated in this TOU rate proposal, by rebalancing the revenue recovery between demand and energy charges. This was accomplished by lessening the amount of revenue forecast to be recovered through the energy charge and increasing the amount of revenues to be recovered through the demand component of the rate design for the sub-class.

The bill impacts arising from the introduction of the TOU rate design and the 50% demand ratchet are shown in the figure below. Customers experiencing bill impacts of greater than 5% are those with existing contract demand levels significantly exceeding their current operating demand levels, and will have ample opportunity to realign their contract demand levels to mitigate the severity of those bill impacts.

Figure 6.4 Customer Bill Impact Related to Rate Design and Demand Ratchet Change

Customer Bill Impact Related to Rate Design Change
2016 Proxy Rates vs 2016 Proposed TOU Rates
(Including 50% Contract Demand)

	Number of Customers	
	Large 30 - 100 kV	Large >100 kV
Decrease >5%	1	4
Decrease 3% - 5%	1	1
Decrease 1% - 3%	12	3
Increase or Decrease <1%	8	3
Increase 1% -3%	5	1
Increase 3% - 5%	3	0
Increase >5%	8	2
Total Customers	**38**	**14**

6.4 PROPOSED CHANGES TO RATE PROGRAMS

6.4.1 Surplus Energy Program ("SEP")

Manitoba Hydro is seeking confirmation of the rate approval process given proposed change to the Terms and Conditions for Option 1 of the SEP which was proposed in the last GRA, and approved on an interim basis in Order 43/13. This change would allow customers to have a different Reference Demand for each of the three pricing periods. The highest designated Reference Demand would be used in determining the customer's monthly billed demand.

The change would allow eligible General Service Medium and Large customers to nominate different levels of Surplus Energy Program energy purchases in peak periods (5x8 weekdays – day time), off-peak periods (7x8 weekdays – night time), and shoulder periods (other weekday or weekend periods). These changes would allow customers to tailor their Option 1 purchases to minimize costs and/or maximize purchase effectiveness.

The PUB, in Order 43/13 approved the change on an interim basis, to be reviewed at a future hearing. Manitoba Hydro is requesting it be reviewed in this Application and approved as final. While there are currently no customers on Option 1, this change would open the possibility for customers to consider this Option in the future.

A copy of the amended SEP Terms and Conditions are included in Appendix 6.7.

Each year Manitoba Hydro files an annual report with the PUB on the status of the SEP. The current report covering the period November 1, 2013 to October 31, 2014 is included in Appendix 6.8.

6.4.2 Curtailable Rate Program ("CRP")

Manitoba Hydro is seeking confirmation of the rate approval process given proposed changes to the CRP that were approved on an interim basis in Order 43/13.

The following changes were implemented effective May 1, 2013, on an interim basis, pending final approval.

- Cap limitations for CRP load has been reduced to 50 MW for Option R load (from the previous 100 MW) and 180 MW for Option A and C loads (previously 230 MW), assuming that the Option C load will convert to Option A. Should Option C load revert to firm service, then the cap for Option A will be reduced to 150 MW.
- Customer's ability to designate varying monthly curtailable load amounts is no longer available. This feature had never been utilized.
- The previous Terms and Conditions did not allow customers to go back onto the CRP if they have switched their curtailable load to firm service. The interim amended Terms and Conditions allow customers back onto the program provided one year has passed since they went off the program and provided that there is curtailable load available under the cap constraints.
- The "Failure to Curtail" clause has been revised from *"Manitoba Hydro may exclude customers from the Curtailable Rate Program if cumulative additional charges during any contract period equal or exceed cumulative discounts"* to *"Manitoba Hydro may exclude customers from the Curtailable Rate Program if a second or subsequent failure to curtail occurs in any twelve month period."*

The following two changes have not yet been implemented:

- A change in the defined hours for peak and off-peak periods to correspond to the hours being defined for a potential TOU rate offering.
- Curtailment Options "C" and "CE" will no longer be made available. The one customer under Option C (there are no customers on Option CE) will be allowed to remain on this Option for one year from the date of confirmation of the rate approval process associated with the amendments of the CRP Terms and Conditions by the

PUB (the sunset date). The customer will have the ability to switch their curtailable load to Option A provided they do so prior to the sunset date, otherwise their curtailable load will convert to firm service.

On May 15, 2013, Manitoba Hydro advised the PUB that these two changes could not be implemented on an interim basis as they could not be easily reversed. Manitoba Hydro proposed to defer these two changes until such time as the PUB could grant final approval. By letter dated June 25, 2013, the PUB confirmed Manitoba Hydro's approach. Copies of both letters have been provided in Appendix 6.9 to this Tab for reference.

A copy of the CRP Terms and Conditions are included as Appendix 6.10.

Each year Manitoba Hydro files an annual report with the PUB on the status of the CRP. The current report which was filed with the PUB on September 10, 2014 covers the period April 1, 2013 to March 31, 2014 and is included for reference in Appendix 6.11.

Manitoba Hydro is seeking confirmation that the PUB accepts the rates flowing from the changes to the terms and conditions of the SEP and CRP programs that were approved on an interim basis in Order 43/13.

6.5 COST OF SERVICE STUDY AND STAKEHOLDER ENGAGEMENT

Manitoba Hydro last filed a COSS with the PUB in the course of the 2012/13 & 2013/14 General Rate Application, to support its application for the differentiation of rates by customer class to be effective April 1, 2013. Shortly thereafter, the PUB determined that matters associated with the COSS would be heard at a separate regulatory proceeding to be scheduled at a later date. Order 43/13, flowing from the 2012/13 & 2013/14 GRA, approved the increase in rates to be applied on an "across the board" basis to all rate components for all rate classes, effective May 1, 2013.

In 2014, after the conclusion of the "Needs For and Alternatives To" Review of Manitoba Hydro's Preferred Development Plan, the Corporation determined that in light of the significant Generation and Transmission expansion plans and the resulting Recommendations to Government that there was a need to re-examine certain elements of the COSS given this changing environment.

This examination involved internal staff and an external expert, Christensen Associates ("CA") of Madison, Wisconsin undertaking to re-visit certain aspects of the COSS. This initiative also incorporated the use of a stakeholder engagement process to solicit input and alternatives from stakeholders in advance of finalizing its corporate position on these matters.

The purpose of the stakeholder engagement process was to facilitate the sharing of views of COSS methodology in an informal, non-adversarial environment, and to identify possible alternative treatments. This process was also necessitated by the lapse of time since the COSS was last reviewed in a public forum in 2008, and the significant differences in perspectives between Manitoba Hydro and its stakeholders on various COSS assumptions, flowing from Order 116/08.

Manitoba Hydro began planning discussions with stakeholder representatives in August, 2014, which led to the formulation of two workshop sessions that were conducted on October 30, 2014 and December 12, 2014. The workshops were attended by stakeholder representatives and their expert COSS consultants and PUB staff and its engineering technical advisor.

The main topics of discussion in the workshop sessions were:

- Allocation of costs to the export class;
- Treatment of net export revenues;
- Allocation of Demand Side Managements costs;
- Functionalization, classification and allocation of Generation system costs; and,
- Functionalization, classification and allocation of AC Transmission system costs.

The workshops served to provide stakeholders and PUB staff and advisors with a common understanding of Cost of Service matters and presented the parties with the current state of Manitoba Hydro's COSS (PCOSS14). Through the course of each workshop, Manitoba Hydro was able to obtain comments and perspectives from stakeholders on various COSS assumptions and alternative treatments to be considered in future cost of service studies.

Manitoba Hydro intends to assess the input and commentary provided during the workshop sessions and is of the view that this information will be useful in its examination of its COSS. The Corporation will continue its examination of its COSS with a goal of advancing its next COSS for public review at an appropriate time that will be determined in conjunction with the PUB and stakeholders.

6.6 COMPARISON OF ELECTRICITY RATES ACROSS JURISDICTIONS

Figure 6.5 below provides a comparison of the rate increases approved and proposed by other Canadian electric utilities since 2007.

Figure 6.5 Utility Rate Changes

	2007	2008	2009	2010	2011	2012	2013	2014	2015	Cumulative	Current Rate Index*
Manitoba Hydro	2.25%	5.00%	2.90%	2.80%	2.00%	4.40%	3.50%	2.75%	3.95% Proposed	33.7%	100
Hydro Quebec	1.90%	2.90%	1.20%	0.35%	-0.40%	-0.50%	2.41%	4.30%	3.90% Proposed	17.1%	104
BC Hydro	2.10%	0.83%	9.28%	7.29%	7.77%	7.07%	1.44%	9.00%	6.00%	63.2%	134
SaskPower	4.20%	0.00%	8.50%	4.50%	0.00%	0.00%	4.90%	5.50%	3.00%	34.7%	149
NB Power	5.90%	3.00%	3.00%	3.00%	0.00%	0.00%	2.00%	2.00%	2.00% Proposed	20.4%	159
NS Power	3.80%	0.00%	9.30%	0.00%	6.05%	8.70%	3.00%	3.00%	N/A	38.7%	194

* This index is based on the Edison Electric Institute's Survey and compares the average price per kWh (in Canadian $) for the various utilities. Manitoba Hydro's average price is $0.0627/kWh. The Survey is based on 12 months data ending June 2014.

Manitoba Hydro uses its annual "Survey of Canadian Electricity Bills" (which can be found in Appendix 6.14) to compare bills paid by Manitoba customers with those of other major Canadian utilities. As demonstrated in Figure 6.6 below, based on the 2014 Survey of Canadian Electricity Bills, electricity rates in Manitoba are at or near the low end of rates in comparison to other large Canadian cities.

Figure 6.6 2014 Survey of Canadian Electricity Bills Rate Comparison (Price per kWh)

	Residential		GS – Small		GS - Medium		GS - Large	
	1,000 kWh	2,000 kWh	1,000 kWh	5,000 kWh	120 MWh	200 MWh	5.5 GWh	12 GWh
Vancouver BC	9.71	10.77	11.31	10.76	7.62	7.66	6.95	5.47
Edmonton AB	13.14	12.08	13.53	12.46	n/a	n/a	n/a	n/a
Calgary AB	15.66	14.60	17.90	14.65	11.19	11.01	10.35	n/a
Regina SK	13.95	12.94	14.08	11.88	10.15	10.16	7.76	6.31
Winnipeg MB	**8.11**	**7.75**	**9.73**	**8.15**	**6.24**	**6.18**	**4.90**	**3.99**
Toronto ON	15.58	14.64	17.53	15.89	13.23	13.21	12.07	11.80
Montreal PQ	7.06	7.66	10.61	9.63	8.23	8.23	5.06	4.81
Halifax NS	16.03	15.49	16.33	15.38	12.83	12.83	9.13	8.83
Moncton NB	12.06	11.05	14.45	12.74	11.20	11.19	7.24	7.04
St. John's NL	12.33	11.55	12.92	11.81	10.13	9.83	8.56	8.29

n/a - did not respond to Manitoba Hydro's survey
Reflects rates in effect May 1, 2014

To measure performance in the overall North American context, Manitoba Hydro uses the results of both the Edison Electric Institute ("EEI") survey as well as monthly statistics obtained from the United States Department of Energy ("DOE"). Unlike the EEI data that provides investor-owned utility comparisons, the DOE data provides comparisons by State which includes numerous utilities within that state. The table below provides the Total Retail Average Rate compared to other low-cost jurisdictions and neighbouring utilities, including primary MISO states, based on the June 2014 DOE data and July 1, 2014 EEI data, using an exchange rate of 1 US $ =1.1423 Canadian as of December 5, 2014.

The Average Retail Rate provided in Figure 6.7 was determined by dividing the combined total revenue billed by the combined total kilowatt hours billed for the 12-month period ending June 30, 2014 for all customer classes (residential, commercial and industrial), whereas the price per kilowatt hour in Figure 6.6, based on Manitoba Hydro's Survey of Canadian Electricity Bills, are provided for each customer class based on specific levels of consumption.

Figure 6.7 Total Retail Average Rate (Canadian $)

State / Province	Cents per kWh
Manitoba	6.27
Quebec	6.51
Washington	7.78
British Columbia	8.39
West Virginia	8.74
Wyoming	8.94
Saskatchewan	9.33
Idaho	9.38
Arkansas	9.39
Kentucky	9.60
South Dakota	10.78
North Dakota	10.84
Minnesota	11.58
Wisconsin	12.70

Electric utilities across Canada are facing similar cost pressures as Manitoba Hydro which are driving higher than inflationary rate increases. A summary of the reasons for proposed rate increases of comparable Canadian utilities is provided below.

In its 10 year plan for BC Hydro, the British Columbia government established electricity rate increases for BC Hydro of 9.0% in 2014 and 6.0% in 2015. The rate increases for 2016, 2017 and 2018 have been capped by the BC government at 4%, 3.5% and 3.0% respectively. The actual rate increases for 2016-2018 will be established by the British Columbia Utilities Commission. The main driver behind these rate increases is the need to fund investments in aging and new infrastructure to meet growing demand. BC Hydro is forecasting a significant increase in electricity demand over the next 20 years, driven by population increases and broad economic expansion, including increased demand associated with Liquefied Natural Gas industry development. Over the next 10 years, BC Hydro forecasts that capital expenditures will amount to approximately $1.7 billion per year. This level of capital investment will be required to refurbish, upgrade, and expand the electricity generation, transmission and distribution system.

The Saskatchewan Rates Review Panel, approved a rate increase for SaskPower of 5.5% effective January 1, 2014. A further rate increase of 3% was implemented effective January 1, 2015. The rate increases are required primarily to support load growth over the next decade, and to support investments in aging generation, transmission and distribution infrastructure. SaskPower is investing an estimated $1 billion per year over the long term to renew and modernize its electricity system. The majority of the increase in SaskPower's expenses in 2014 and 2015 (depreciation & amortization expense, finance expense and capital taxes) are being driven by increased capital investment. Other drivers include increased fuel and power purchase costs associated with changes in SaskPower's generation mix.

Nova Scotia Power's rates increased by 3% in each of 2013 and 2014. The rate increases were set as part of a rate stabilization plan whereby a portion of the revenue requirement not recovered through current rates is being deferred for recovery in future years. In absence of a rate stabilization plan, the rate increases would have been 7.2% in 2013 and 2.8% in 2014. The main drivers of the rate increases were reduced load, infrastructure additions and upgrades, and increases in fuel costs. Nova Scotia Power's two largest customers (both in the pulp and paper industry) shut down in 2012. Moreover, total sales to other customers have also declined. Throughout 2013 and 2014, Nova Scotia Power made investments in renewable energy projects including a biomass plant, and wind farms. In addition, increased capital investments in the distribution and transmission systems were required to improve reliability and prepare the system to receive intermittent renewable energy.

The Regie de l'energie approved an average rate increase of 4.3% for Hydro-Quebec effective April 1, 2014, applicable to all customer classes except the large industrial customer class. The rate increase authorized for the large industrial customer class was 3.5%. The key drivers of rate increases for Hydro-Quebec are the purchasing costs of wind energy, and the costs associated with upgrading the distribution and transmission networks. On August 1 2014, Hydro-Quebec submitted its 2015-2016 distribution rate application. The total requested rate increase is 3.9% for all customer classes, except for the large industrial customer class for which the requested rate increase is 3.5%.

In November 2013, the Ontario government released its 2013 Long Term Energy Plan (the "Plan"), which outlines Ontario's plans for encouraging conservation and providing for a clean, reliable and affordable energy future. The Plan provides residential electricity bill forecasts over the period 2013-2032. Although these are not based on underlying proposed rate increases by a particular entity, they do indicate that Ontario residential and industrial customers could see their bills increase over the 2014 to 2018 time period. For residential customers, electricity bills are estimated to increase by approximately 9.6% in 2014, 5.8% in 2015,15% in 2016,1.8% in 2017, and 4.7% in 2018. Furthermore, Ontario industrial customers could see their electricity bills increase by approximately 10% in 2014, 5.7% in 2015, 4.3% in 2016, 4.2% in 2017, and 5.0% in 2018.

The issue of aging infrastructure is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the rate increases being projected in IFF14, it is expected that Manitoba's domestic electricity customers will continue to have rates that are affordable and competitive with other utilities in North America.

Despite having competitive rates, Manitoba Hydro acknowledges that bill increases have an impact on customers. As discussed in Tab 8, Manitoba Hydro, as part of its Power Smart suite, offers programs to assist customers in managing their energy consumption through the implementation of energy efficiency opportunities in their homes and businesses. These opportunities not only result in energy bill savings in the short and long term, but also result in a more comfortable environment for customers. Moreover, to assist low-income customers, Manitoba Hydro continues to provide targeted and enhanced support through its Affordable Energy Program, to improve the energy efficiency of their homes resulting in lower energy bills and increased comfort.

PROOF OF REVENUE

Current May 1, 2014 Rates vs Proposed April 1, 2015 Rates

Annualized for year ended March 31, 2016

	Calculated Revenue Current Rate	Calculated Revenue Prop. Rate	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic	$592,844,674	$616,234,993	$23,390,318	3.95%
Diesel	$720,668	$749,102	$28,434	3.95%
Seasonal	$8,656,423	$8,998,455	$342,031	3.95%
FRWH	$1,102,053	$1,145,633	$43,580	3.95%
Residential	**$603,323,819**	**$627,128,183**	**$23,804,364**	**3.95%**
Small Non-Demand	$144,199,403	$149,893,184	$5,693,781	3.95%
Small Demand	$143,343,984	$149,006,651	$5,662,666	3.95%
Seasonal	$621,841	$646,400	$24,559	3.95%
FRWH	$509,649	$529,780	$20,132	3.95%
GS Small	$288,674,878	$300,076,016	$11,401,138	3.95%
GS Medium	$202,418,940	$210,413,370	$7,994,431	3.95%
Large 750 V-30 kV	$92,433,681	$96,084,111	$3,650,430	3.95%
Large 30 - 100 kV	$73,318,053	$76,216,131	$2,898,078	3.95%
Large > 100 kV	$182,780,545	$190,004,279	$7,223,734	3.95%
GS Large	$348,532,279	$362,304,520	$13,772,241	3.95%
Diesel GS & Gov.	$6,229,635	$6,475,802	$246,167	3.95%
SEP	$1,230,924	$1,230,924	$0	0.0%
General Service	**$847,086,654**	**$880,500,632**	**$33,413,977**	**3.94%**
A & R Lighting	**$22,905,519**	**$23,810,832**	**$905,313**	**3.95%**
DSM Reduction	($25,533,487)	($26,541,448)	($1,007,961)	3.95%
Misc. Rev & Adjs	$6,605,049	$6,865,950	$260,901	3.95%
GENERAL CONSUMERS	**$1,454,387,555**	**$1,511,764,149**	**$57,376,594**	**3.95%**

PROOF OF REVENUE

Proposed April 1, 2015 Rates vs Proposed April 1, 2016 Rates

Annualized for year ended March 31, 2017

	Calculated Revenue Current Rate	Calculated Revenue Prop. Rate	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic	$626,416,557	$651,162,390	$24,745,833	3.95%
Diesel	$764,568	$794,772	$30,203	3.95%
Seasonal	$9,147,505	$9,509,037	$361,533	3.95%
FRWH	$1,088,489	$1,131,467	$42,978	3.95%
Residential	**$637,417,119**	**$662,597,666**	**$25,180,548**	**3.95%**
Small Non-Demand	$152,681,555	$158,707,425	$6,025,870	3.95%
Small Demand	$151,505,257	$157,487,821	$5,982,564	3.95%
Seasonal	$650,061	$675,721	$25,660	3.95%
FRWH	$503,600	$523,493	$19,893	3.95%
GS Small	$305,340,473	$317,394,460	$12,053,987	3.95%
GS Medium	$214,164,398	$222,626,087	$8,461,689	3.95%
Large 750 V-30 kV	$98,633,036	$102,540,203	$3,907,167	3.95%
Large 30 - 100 kV	$84,273,828	$87,606,376	$3,332,547	3.95%
Large > 100 kV	$180,966,585	$188,108,544	$7,141,960	3.95%
GS Large	$363,873,449	$378,255,123	$14,381,674	3.95%
Diesel GS & Gov.	$6,492,627	$6,749,035	$256,408	3.95%
SEP	$1,359,873	$1,359,873	$0	0.00%
General Service	**$891,230,821**	**$926,384,579**	**$35,153,758**	**3.94%**
A & R Lighting	**$23,929,400**	**$24,875,091**	**$945,691**	**3.95%**
DSM Reduction	($41,389,314)	($43,023,107)	($1,633,794)	3.95%
Misc. Rev & Adjs	$6,661,117	$6,924,200	$263,083	3.95%
GENERAL CONSUMERS	**$1,517,849,143**	**$1,577,758,429**	**$59,909,286**	**3.95%**

PROPOSED

RATE SCHEDULES

TO BE EFFECTIVE

APRIL 1, 2015

Manitoba Hydro

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DEFINITIONS

All Rates Schedules in the publication are applied on a MONTHLY basis except as noted.

The following expressions shall have the following meanings:

a) "Basic Charge": a fixed charge that that does not change with the amount of electricity used. This includes the direct costs of metering, portions of the distribution system, as well as billing administration.

b) "Billing Demand": The greatest of the following (expressed in kVA)
   i. measured demand; or
   ii. 25 % of contract demand; or
   iii. 25% of the highest measured demand in the previous 12 months.

c) "Billing Month": the period of time, generally 30 days, in which Energy and/or Demand is consumed and thereafter billed to the Customer.

d) "Demand": the maximum use of power within a specified period of time.

e) "Demand Charge": that portion of the charge for electric service based upon the electric capacity (kVA) consumed and billed on the basis of the billing demand under an applicable rate schedule.

f) "Energy": power integrated over time and measured or expressed in kilowatt-hours (kWh).

g) "Energy Charge": that portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

h) "Kilo-Volt Amperes (kVA)": also referred to as apparent power, is the product of the volts times current of a circuit divided by 1000. It is composed of both real and reactive power.

i) "Kilowatt Hour (kWh)": the basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

j) "Measured Demand": the highest demand recorded in the Billing Month.

k) "Power Factor": is the ratio of real power (kW) to apparent power (kVA) for any given load and time. Generally it is expressed as a percentage ratio.

l) "Watt (W)": the electrical unit of power or rate of doing work; the rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

RESIDENTIAL RATES

RESIDENTIAL - *TARIFF NO. 2015-01*

Basic Charge:	$ 7.57
PLUS	
Energy Charge:	
All kWh	@ 7.672¢ / kWh
Minimum Bill:	$ 7.57

Services over 200 amps will have $7.57 added to the Basic Charge.

Applicability:

The Residential rate is applicable for all residential purposes as follows:

a) individually metered single family dwellings including those in multiple residential projects and single or three phase farm operations served through the same meter if:

   i. the connected business load does NOT exceed 3 kW; or
   ii. the combined agricultural and residential load does NOT exceed a demand of 50 kW.

b) services for personal use outside the home, such as residential water wells, private garages, boat houses and swimming pools (use can be for household, recreational and hobby activities).

c) single metered multiple residential projects meeting all the following criteria:

   i. monthly demand does not exceed 50 kVA;
   ii. the meter serves four or less individual suites or dwelling units;
   iii. none of the units are used for business purposes;
   iv. individual dwelling units are:
      - self-contained rental apartments with common facilities; or
      - row housing with self-contained rental dwelling units and common facilities; or
      - buildings with condominium type dwellings incorporated under *the Condominium Act*; or individual residential services within a trailer park established prior to May 1, 1969.

RESIDENTIAL RATES

SEASONAL - *TARIFF NO. 2015-02*

Annual Basic Charge:	$ 90.84
PLUS	
Energy Charge:	
All kWh	@ 7.672 ¢ / kWh
Minimum Annual Bill:	$ 90.84

The account is billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season's consumption. The October billing is for the summer season's consumption only.

Applicability:

The Seasonal rate is applicable to customers outside of the Winnipeg area using less than 7,500 kWh per season and is for residential purposes on an individually metered service when usage is of a casual or intermittent nature.

DIESEL - *TARIFF NO. 2015-03*

Basic Charge:	$ 7.57
PLUS	
Energy Charge:	
All kWh	@ 7.672 ¢ / kWh
Minimum Bill:	$ 7.57

Applicability:

The Residential rate applies to all residential services in the Diesel Communities, provided the service capacity does not exceed 60 A, 120/240 V, single phase.

RESIDENTIAL

FLAT RATE WATER HEATING RATES

(NOT available for new services)

	TARIFF NO. 2015-09	***TARIFF NO. 2015-10***
Element Size	Controlled	Uncontrolled
500 W	$ 11.81	$ 15.62
600 W	$ 14.00	$ 18.58
750 W	$ 17.18	$ 22.91
900 W	$ 20.43	$ 27.23
1,000 W	$ 22.53	$ 30.15
1,200 W	$ 25.58	$ 33.83
1,250 W	$ 26.34	$ 34.80
1,500 W	$ 30.15	$ 39.26
2,000 W	$ 36.28	$ 47.34
2,500 W	$ 40.85	$ 53.04
3,000 W	$ 44.71	$ 58.80
3,500 W	$ 50.25	$ 65.50
4,000 W	$ 55.72	$ 72.19
4,500 W	$ 62.23	$ 80.16
6,000 W	$ -	$ 103.83
1,500 / 1,000 W	$ 23.45	$ 31.36
2,000 / 1,000 W	$ 24.05	$ 32.13
3,000 / 1,000 W	$ 24.57	$ 33.27
2,000 / 1,500 W	$ 32.64	$ 43.63
3,000 / 1,500 W	$ 33.41	$ 44.46
4,500 / 1,500 W	$ 34.55	$ 46.23
3,000 / 2,000 W	$ 40.12	$ 53.78

Applicability:

Available only for services continuously energized since November 11, 1969.

GENERAL SERVICE

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

SMALL SINGLE PHASE - *TARIFF NO. 2015-20*

Basic Charge:	$ 20.51
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.058 ¢ / kWh
Next 8,500 kWh	@ 5.594 ¢ / kWh
Balance of kWh	@ 3.692 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.45 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

SMALL THREE PHASE - *TARIFF NO. 2015-21*

Basic Charge:	$ 28.92
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.058 ¢ / kWh
Next 8,500 kWh	@ 5.594¢ / kWh
Balance of kWh	@ 3.692 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.45 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

Accounts where the Monthly Billing Demand is 50 kVA or less within the past 12-month period, ALL energy in excess of 11,000 kWh will be charged @ 5.594 ¢ / kWh.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Applicability:

The General Service Small Rate is applicable to:

a) service with Utility-Owned transformation for all non-residential purposes including churches, community clubs and other community service and recreation facilities and all commercial and general purposes wherein the conduct of business activities or operation is associated with the distribution of goods and/or services.

b) occupied dwellings where the connected business load exceeds 3 kW to not exceeding 200 kW.

c) single metered multiple residential projects meeting any of the following criteria:

    i. monthly demand exceeds 50 kVA to not exceeding 200 kVA ; or
    ii. the meter serves five or more individual suites or dwelling units; or
    iii. any of the units are used for business purposes.

d) farm services:

    i. without an occupied dwelling being used for agricultural or commercial purposes; or
    ii. where the connected business load exceeds 3 kW to not exceeding 200 kW; or
    iii. where the combined agricultural and residential load exceeds a demand of 50 kVA to not exceeding 200 kVA.

GENERAL SERVICE

0 TO NOT EXCEEDING 50 kVA

(Utility-Owned Transformation)

SEASONAL - *TARIFF NO. 2015-22*

Annual Basic Charge:	$ 246.12
PLUS	
First 66,000 kWh	@ 8.058 ¢ / kWh
Balance of kWh	@ 5.594 ¢ / kWh
Minimum Annual Bill:	$ 246.12

SEASONAL THREE PHASE - *TARIFF NO. 2015-27*

Annual Basic Charge:	$ 347.04
PLUS	
First 66,000 kWh	@ 8.058 ¢ / kWh
Balance of kWh	@ 5.594 ¢ / kWh
Minimum Annual Bill:	$ 347.04

The account is billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season's consumption. The October billing is for the summer season's consumption only.

Applicability:

The General Service Seasonal rate is applicable for businesses outside of the Winnipeg area whose:

a) demand does NOT exceed 50 kVA;
b) usage is of an intermittent or casual nature;
c) consumption is primarily summer time and usage is limited in the winter; and
d) business load is greater than 3 kW in a residence.

GENERAL SERVICE

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

COOKING AND HEATING STANDARD - *TARIFF NO. 2015-23*

Basic Charge:	$ 20.51
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.058 ¢ / kWh
Balance of kWh	@ 5.594 ¢ / kWh
Minimum Bill:	$ 20.51

COOKING AND HEATING SEASONAL - *TARIFF NO. 2015-24*

Annual Basic Charge:	$ 246.12
PLUS	
Energy Charge:	
First 66,000 kWh	@ 8.058 ¢ / kWh
Balance of kWh	@ 5.594 ¢ / kWh
Minimum Annual Bill:	$ 246.12

Seasonal Cooking and Heating accounts are billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season’s consumption. The October billing is for the summer season’s consumption only.

Applicability:

The General Service Cooking and Heating rate is applicable to services existing prior to April 1, 1976 for separately metered cooking, heating, process heating or car plug service in the same building or an extension of that building where the primary requirement is for General Service.

GENERAL SERVICE

DIESEL - *TARIFF NO. 2015-40*

Basic Charge:	$ 20.51
PLUS	
Energy Charge:	
First 2,000 kWh	@ 8.058 ¢ / kWh
Balance of kWh	@ 41.232 ¢ / kWh
Minimum Bill:	$ 20.51

The General Service rate applies to all commercial accounts excluding those classed as Government and /or First Nation Education.

GOVERNMENT AND FIRST NATION EDUCATION - *TARIFF NO. 2015-41*

Basic Charge:	$ 20.51
PLUS	
Energy Charge:	@ $2.5095 / kWh
Minimum Bill:	$ 20.51

The First Nation Education rate is applicable to all Diesel First Nation facilities providing instructional services for members of the Diesel First Nations, including schools, teacherages and student residences.

GENERAL SERVICE

EXCEEDING 200 kVA

(Utility-Owned transformation)

MEDIUM - *TARIFF NO. 2015-30*

Basic Charge:	$ 30.52
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.058 ¢ / kWh
Next 8,500 kWh	@ 5.594 ¢ / kWh
Balance of kWh	@ 3.692 ¢ / kWh
PLUS	
* Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.45 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Applicability:

The General Service Medium rate is applicable to services where the registered demand exceeds 200 kVA and where the transformation is provided by the Corporation.

Customers who, by nature of their business, do not require service during the months of December, January, and February may qualify for the General Service Short-Term Power rate. For further details see page 16.

GENERAL SERVICE

(Customer-Owned Transformation)

LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2015-60*

Energy Charge:	@ 3.472 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 8.02 / kVA

Minimum Bill: Demand Charge

LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2015-61*

Energy Charge:	@ 3.228 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 6.87 / kVA

Minimum Bill: Demand Charge

LARGE EXCEEDING 100 KV - *TARIFF NO. 2015-62*

Energy Charge:	@ 3.128 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 6.11 / kVA

Minimum Bill: Demand Charge

<u>Monthly Billing Demand</u> *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

<u>Applicability</u>:

The General Service Large rate is applicable to services where the transformation is provided by the customer and connected directly to the Corporation’s distribution, subtransmission or transmission lines.

Customers who, by nature of their business, do not require service during the months of December, January and February may qualify for the General Service Short-Term Power rate.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

LUBD SMALL SINGLE PHASE - *TARIFF NO. 2015-50*

Basic Charge:	$ 20.51
PLUS	
Energy Charge:	@ 9.146¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.36 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge:

LUBD SMALL THREE PHASE - *TARIFF NO. 2015-51*

Basic Charge:	$ 28.92
PLUS	
Energy Charge:	@ 9.146¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.36 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge:

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Eligibility:

Any customer eligible for service on the General Service Small rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Small rates.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

EXCEEDING 200 kVA

(Utility-Owned Transformation)

LUBD MEDIUM - *TARIFF NO. 2015-52*

Basic Charge:	$ 30.52
PLUS	
Energy Charge:	@ 9.146 ¢ / kWh
PLUS	
* Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.36 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

<u>Monthly Billing Demand</u> *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25% of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

<u>Eligibility:</u>

Any customer eligible for service on the General Service Medium rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Medium rates.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

(Customer-Owned Transformation)

LUBD LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2015-53*

Energy Charge:	@ 8.095 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 2.01 / kVA

Minimum Bill: Demand Charge

LUBD LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2015-54*

Energy Charge:	@ 7.190 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 1.72 / kVA

Minimum Bill: Demand Charge

LUBD LARGE EXCEEDING 100 KV - *TARIFF NO. 2015-55*

Energy Charge:	@ 6.653¢ / kWh
PLUS	
* Demand Charge:	@ $ 1.53 / kVA

Minimum Bill: Demand Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Eligibility:

Any customer eligible for service on the General Service Large rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Large rates.

GENERAL SERVICE

FLAT RATE WATER HEATING RATES

(NOT available for new services)

TARIFF NO. 2015-29

Element Size	Uncontrolled
500 W	$ 16.62
600 W	$ 19.88
750 W	$ 24.81
1,000 W	$ 33.35
1,200 W	$ 39.90
1,500 W	$ 49.64
2,000 W	$ 62.23
2,500 W	$ 74.83
3,000 W	$ 87.07
3,500 W	$ 99.31
3,800 W	$ 109.77
4,000 W	$ 111.56
4,500 W	$ 123.81
5,000 W	$ 136.05
6,000 W	$ 160.54
6,500 W	$ 177.75
7,000 W	$ 185.00
7,500 W	$ 202.92
8,000 W	$ 209.48
9,000 W	$ 233.95
10,000 W	$ 258.46
10,500 W	$ 270.75
12,000 W	$ 307.45
12,500 W	$ 319.70
13,000 W	$ 331.95
13,500 W	$ 344.05
14,500 W	$ 368.54
15,000 W	$ 380.89
16,000 W	$ 405.38
16,500 W	$ 429.59
18,000 W	$ 454.41
19,000 W	$ 492.48
20,000 W	$ 503.35
23,000 W	$ 593.25
24,000 W	$ 618.47
25,000 W	$ 625.70
3,000 / 1,000 W	$ 40.63
2,000 / 1,500 W	$ 51.44
3,000 / 1,500 W	$ 52.01
4,500 / 1,500 W	$ 53.28

GENERAL SERVICE

Short-Term Power Rate

The General Service Short-Term application is available throughout the Province of Manitoba except in the Diesel Zone, for customers with services exceeding 200 kVA who, by the nature of their business, do not require service during the months of December, January, and February. Qualifying customers will be billed at, and subject to the conditions of, the appropriate General Service Medium or Large rate.

Services must be disconnected from 00:00 hours, December 1 to 24:00 hours, February 28/29. Customers may use up to a maximum of 1,000 kWh during these months for security purposes only (i.e. alarm system, security lighting) but must notify Manitoba Hydro each year in advance of their operation shutdown.

Service must be taken for a minimum of four months, normally consecutively, during the period March 1 to November 30. Customers will be subject to the same 25% ratchet provisions as applicable to General Service Medium and Large customers, with the exception that no ratchets will apply for the months of December, January or February unless the customer exceeds the 1,000 kWh per month allowable use during those months.

General Service Short-Term is NOT available in conjunction with other services at the same point of delivery.

Unmetered Services

Billed on the General Service Small Rate Tariff No. 2015-20 or 2015-21:

The Unmetered Service rate is applicable:

a) for non-residential customers where the load is constant and the consumption is consistent and metering is unnecessary or undesirable, specifically including traffic signals, pedestrian walkway lighting, directional traffic signs, hazard flashers, cable television power amplifiers, telephone booths, transit shelters (both heated and unheated), cathodic protection rectifiers (for oil and natural gas pipelines), water gauge wells, highway traffic counters, governmental navigational lights (both nautical and aerial), municipal sirens and Canadian Emergency Measures Organization emergency siren alarms.

b) for existing railway crossings, sign lighting and window lighting. Customers will be required to provide metering facilities if additional load is connected.

c) for services such as fairs, summer midways, television production and welding schools where service is required for less than 30 days.

d) for oil field pumping services connected prior to April 1, 1980 with oil pumping motors of the counter balanced (nodding or piston) type.

GENERAL SERVICE

SHORT-DURATION, INTERMITTENT RATE

TERMS AND CONDITIONS

General

Manitoba Hydro will supply short-duration, intermittent power and energy to customers whose operation requires short periods of high demand combined with overall, very low energy consumption.

The Corporation may regulate timing of the customer's demand requirements so that they do not coincide with other system peak demands.

The Corporation may interrupt the supply at any time, for any length of time and for any reason.

Conditions of Service

Qualifying customers will be billed at, and subject to the conditions of, the appropriate General Service Large or Medium rate with the following provisions:

a) Measured demand will be reduced by 50% for billing purposes.

b) Customers will be assessed a monthly energy entitlement based on a 1% load factor (monthly demand x 0.01 x 730) to be billed at the applicable General Service rate.

c) Energy consumption in excess of the monthly energy entitlement will be billed at a rate equal to 10 times the usual applicable General Service rate.

Customers will be required to enter into a formal contract with Manitoba Hydro. The contract will document the above conditions as well as any others considered necessary due to the nature of a specific service.

Rate Application

The General Service Short-Term, Intermittent rate is available to all customers, except those in the Diesel Rate Zone, to customers qualifying for the General Service Large and General Service Medium rates.

AREA AND ROADWAY LIGHTING

OUTDOOR LIGHTING

LEGEND

I	Incandescent
F	Fluorescent
CF	Compact Fluorescent
LED	Light Emitting Diode
MH	Metal Halide
MV	Mercury Vapour
HPS	High Pressure Sodium Vapour
Q	Quartz

Exclusive Pole:	A corporate-owned pole for the primary purpose of supporting outdoor lighting devices.
Shared Pole:	A pole of the primary purpose of supporting electrical circuits other than outdoor lighting.

AREA AND ROADWAY LIGHTING

(Incandescent and Mercury Vapour are NOT available for new installations)

OUTDOOR LIGHTING RATE - *TARIFF NO. 2015-80:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
200 F	-	$ 10.32
20 CF	-	$ 2.21
100 I	$ 4.75	$ 10.32
150 I	-	$ 10.32
300 I	-	$ 14.72
500 I	$ 12.43	$ 20.28
400 MH	-	$ 24.71
175 MV	$ 9.19	$ 14.72
250 MV	$ 10.52	$ 16.66
400 MV	$ 14.43	$ 19.93
70 HPS	$ 7.90	$ 12.97
70 HPS 24 hours	-	$ 14.58
100 HPS	$ 8.20	$ 13.68
150 HPS	$ 10.05	$ 15.45
250 HPS	$ 12.81	$ 17.81
400 HPS	$ 14.70	$ 24.71
400 HPS 2/100'	-	$ 38.20
400 HPS 4/100'	-	$ 28.06
750 HPS	$ 22.78	$ 36.13
1 000 HPS	-	$ 41.91
1 000 HPS 1/60'	-	$ 42.88
1 000 HPS 2/100'	-	$ 51.39
1 000 HPS 4/100'	-	$ 44.07
10 LED (1 – 30 W)	-	$ 2.02
40 LED (> 30 – 50 W)	$ 6.79	$ 11.86
40 LED 24 hr (> 30 – 50 W)	-	$ 13.47
60 LED (> 50 – 80 W)	$ 6.93	$ 12.41
90 LED (> 80 – 120 W)	$ 8.30	$ 13.70
150 LED (> 120 – 180 W)	$ 9.89	$ 14.89
250 LED (> 180 – 280 W)	$ 10.03	$ 20.04
250 LED 2/100' (> 180 – 280 W)	-	$ 33.53
250 LED 4/100' (> 180 – 280 W)	-	$ 23.39

Applicability:

The Area and Roadway rate is available throughout the Province of Manitoba and applies to area and roadway lighting installed by agreement for public authorities.

AREA AND ROADWAY LIGHTING

(NOT available for new installations)

FLOOD LIGHTING RATE - *TARIFF NO. 2015-81:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
100 I	$ 5.38	-
150 I	$ 5.38	$ 11.16
300 I	$ 9.81	-
500 I	$ 13.21	$ 21.62
250 MV	$ 12.16	$ 17.79
400 MV	$ 14.86	$ 19.96
500 Q	$ 20.43	$ 25.89

Applicability:

The Floodlighting rate is applicable for floodlighting services existing prior to April 1, 1976 for lighting of public buildings, structures, monuments, parks, grounds and Department of Highways overhead signs served from the Corporation distribution system where the Corporation owns and maintains the luminaires.

AREA AND ROADWAY LIGHTING

SEASONAL RATE - *TARIFF NO. 2015-82:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
70 HPS	$ 7.90	$ 12.97
100 HPS	$ 8.20	$ 13.68
150 HPS	$ 10.05	$ 15.45
250 HPS	$ 12.81	$ 17.81

Applicability:

The Seasonal Area and Roadway Lighting rate is available only outside the City of Winnipeg and is applicable for area and roadway lighting installed by agreement for Municipal Corporation, local government districts, Provincial and Federal Governments.

Lighting will be energized from May 1 to October 31 of each year and will be disconnected from November 1 to April 30.

AREA AND ROADWAY LIGHTING

SENTINEL LIGHTING RATE - *TARIFF NO. 2015-83:*

Watts	Rate Per Month	
	Flat Rate (Energy and Rental)	Metered (Rental Only)
100 HPS	$ 10.17	$ 7.01
150 HPS	$ 13.47	$ 9.57
175 MV	$ 10.50	$ 7.01
400 MV	$ 17.37	$ 9.57

Applicability:

Sentinel lighting is available for security lighting of private or public areas on a dusk-to-dawn basis throughout the Province of Manitoba. Rental units are intended for continuous year-round service and are not provided on a temporary basis.

Sentinel lighting is available for rental as follows:

a) on a flat rate basis when connected directly to the Manitoba Hydro distribution system; or
b) exclusive of electricity if connected to the customer's metered circuits.

AREA AND ROADWAY LIGHTING

FESTOON LIGHTING - *TARIFF NO. 2015-84*

Connected load @ $0.906/ kW per night of scheduled use:

Minimum Monthly Bill: $ 18.50

Applicability:

The Festoon Lighting rate is applicable only for existing unmetered municipally-owned festoon light strings suspended across streets and public thoroughfares. The customer is required to advise the Corporation prior to any changes in the nights contract for operation and/or the connected lighting kilowatts.

DECORATIVE LIGHTING - *TARIFF NO. 2015-85*

Connected load @ $0.906/kW per night of scheduled use:

Minimum Monthly Bill: $ 18.50

Applicability:

The Decorative Lighting rate is applicable for new and existing unmetered municipally-owned decorative lights on frames or modules mounted on roadway lighting poles or ornamental standards and/or Christmas trees. The customer is required to advise the Corporation prior to any change in the nights contracted for operation and\or the connected lighting kilowatts.

CHRISTMAS LIGHTING - *TARIFF NO. 2015-86*

Connected load @ $0.0723/ kWh.

Applicability:

The Christmas Lighting rate is applicable to the City of Winnipeg Christmas lighting only. The customer is required to advise the Corporation prior to any change in the connected load.

PROPOSED

RATE SCHEDULES

TO BE EFFECTIVE

APRIL 1, 2016

Manitoba Hydro

TABLE OF CONTENTS

DEFINITIONS

All Rates Schedules in the publication are applied on a MONTHLY basis except as noted.

The following expressions shall have the following meanings:

a) "Basic Charge": a fixed charge that that does not change with the amount of electricity used. This includes the direct costs of metering, portions of the distribution system, as well as billing administration.

b) "Billing Demand": The greatest of the following (expressed in kVA)
   i. measured demand; or
   ii. % of contract demand; or
   iii. % of the highest measured demand in the previous 12 months.

c) "Billing Month": the period of time, generally 30 days, in which Energy and/or Demand is consumed and thereafter billed to the Customer.

d) "Demand": the maximum use of power within a specified period of time.

e) "Demand Charge": that portion of the charge for electric service based upon the electric capacity (kVA) consumed and billed on the basis of the billing demand under an applicable rate schedule.

f) "Energy": power integrated over time and measured or expressed in kilowatt-hours (kWh).

g) "Energy Charge": that portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

h) "Kilo-Volt Amperes (kVA)": also referred to as apparent power, is the product of the volts times current of a circuit divided by 1000. It is composed of both real and reactive power.

i) "Kilowatt Hour (kWh)": the basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

j) "Measured Demand": the highest demand recorded in the Billing Month.

k) "Power Factor": is the ratio of real power (kW) to apparent power (kVA) for any given load and time. Generally it is expressed as a percentage ratio.

l) "Watt (W)": the electrical unit of power or rate of doing work; the rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

RESIDENTIAL RATES

RESIDENTIAL - *TARIFF NO. 2016-01*

Basic Charge:	$ 7.87
PLUS	
Energy Charge:	
All kWh	@ 7.975¢ / kWh
Minimum Bill:	$ 7.87

Services over 200 amps will have $7.87 added to the Basic Charge.

<u>Applicability</u>:

The Residential rate is applicable for all residential purposes as follows:

a) individually metered single family dwellings including those in multiple residential projects and single or three phase farm operations served through the same meter if:

  i. the connected business load does NOT exceed 3 kW; or
  ii. the combined agricultural and residential load does NOT exceed a demand of 50 kW.

b) services for personal use outside the home, such as residential water wells, private garages, boat houses and swimming pools (use can be for household, recreational and hobby activities).

c) single metered multiple residential projects meeting all the following criteria:

  i. monthly demand does not exceed 50 kVA;
  ii. the meter serves four or less individual suites or dwelling units;
  iii. none of the units are used for business purposes;
  iv. individual dwelling units are:
    - self-contained rental apartments with common facilities; or
    - row housing with self-contained rental dwelling units and common facilities; or
    - buildings with condominium type dwellings incorporated under *the Condominium Act*; or individual residential services within a trailer park established prior to May 1, 1969.

RESIDENTIAL RATES

SEASONAL - *TARIFF NO. 2016-02*

Annual Basic Charge:	$ 94.44
PLUS	
Energy Charge:	
All kWh	@ 7.975 ¢ / kWh
Minimum Annual Bill:	$ 94.44

The account is billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season's consumption. The October billing is for the summer season's consumption only.

Applicability:

The Seasonal rate is applicable to customers outside of the Winnipeg area using less than 7,500 kWh per season and is for residential purposes on an individually metered service when usage is of a casual or intermittent nature.

DIESEL - *TARIFF NO. 2016-03*

Basic Charge:	$ 7.87
PLUS	
Energy Charge:	
All kWh	@ 7.975 ¢ / kWh
Minimum Bill:	$ 7.87

Applicability:

The Residential rate applies to all residential services in the Diesel Communities, provided the service capacity does not exceed 60 A, 120/240 V, single phase.

RESIDENTIAL

FLAT RATE WATER HEATING RATES

(NOT available for new services)

	TARIFF NO. 2016-09	***TARIFF NO. 2016-10***
Element Size	Controlled	Uncontrolled
500 W	$ 12.28	$ 16.24
600 W	$ 14.55	$ 19.31
750 W	$ 17.86	$ 23.81
900 W	$ 21.24	$ 28.31
1,000 W	$ 23.42	$ 31.34
1,200 W	$ 26.59	$ 35.17
1,250 W	$ 27.38	$ 36.17
1,500 W	$ 31.34	$ 40.81
2,000 W	$ 37.71	$ 49.21
2,500 W	$ 42.46	$ 55.14
3,000 W	$ 46.48	$ 61.12
3,500 W	$ 52.23	$ 68.09
4,000 W	$ 57.92	$ 75.04
4,500 W	$ 64.69	$ 83.33
6,000 W	$ -	$ 107.93
1,500 / 1,000 W	$ 24.38	$ 32.60
2,000 / 1,000 W	$ 25.00	$ 33.40
3,000 / 1,000 W	$ 25.54	$ 34.58
2,000 / 1,500 W	$ 33.93	$ 45.35
3,000 / 1,500 W	$ 34.73	$ 46.22
4,500 / 1,500 W	$ 35.91	$ 48.06
3,000 / 2,000 W	$ 41.70	$ 55.90

Applicability:

Available only for services continuously energized since November 11, 1969.

GENERAL SERVICE

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

SMALL SINGLE PHASE - *TARIFF NO. 2016-20*

Basic Charge:	$ 21.32
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.376 ¢ / kWh
Next 8,500 kWh	@ 5.815 ¢ / kWh
Balance of kWh	@ 3.838 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.82 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

SMALL THREE PHASE - *TARIFF NO. 2016-21*

Basic Charge:	$ 30.06
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.376 ¢ / kWh
Next 8,500 kWh	@ 5.815¢ / kWh
Balance of kWh	@ 3.838 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.82 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

Accounts where the Monthly Billing Demand is 50 kVA or less within the past 12-month period, ALL energy in excess of 11,000 kWh will be charged @ 5.815 ¢ / kWh.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Applicability:

The General Service Small Rate is applicable to:

a) service with Utility-Owned transformation for all non-residential purposes including churches, community clubs and other community service and recreation facilities and all commercial and general purposes wherein the conduct of business activities or operation is associated with the distribution of goods and/or services.

b) occupied dwellings where the connected business load exceeds 3 kW to not exceeding 200 kW.

c) single metered multiple residential projects meeting any of the following criteria:

   i. monthly demand exceeds 50 kVA to not exceeding 200 kVA ; or
   ii. the meter serves five or more individual suites or dwelling units; or
   iii. any of the units are used for business purposes.

d) farm services:

   i. without an occupied dwelling being used for agricultural or commercial purposes; or
   ii. where the connected business load exceeds 3 kW to not exceeding 200 kW; or
   iii. where the combined agricultural and residential load exceeds a demand of 50 kVA to not exceeding 200 kVA.

GENERAL SERVICE

0 TO NOT EXCEEDING 50 kVA

(Utility-Owned Transformation)

SEASONAL - *TARIFF NO. 2016-22*

Annual Basic Charge:	$ 255.84
PLUS	
First 66,000 kWh	@ 8.376 ¢ / kWh
Balance of kWh	@ 5.815 ¢ / kWh
Minimum Annual Bill:	$ 255.84

SEASONAL THREE PHASE - *TARIFF NO. 2016-27*

Annual Basic Charge:	$ 360.72
PLUS	
First 66,000 kWh	@ 8.376 ¢ / kWh
Balance of kWh	@ 5.815 ¢ / kWh
Minimum Annual Bill:	$ 360.72

The account is billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season’s consumption. The October billing is for the summer season’s consumption only.

Applicability:

The General Service Seasonal rate is applicable for businesses outside of the Winnipeg area whose:

a) demand does NOT exceed 50 kVA;
b) usage is of an intermittent or casual nature;
c) consumption is primarily summer time and usage is limited in the winter; and
d) business load is greater than 3 kW in a residence.

GENERAL SERVICE

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

COOKING AND HEATING STANDARD - *TARIFF NO. 2016-23*

Basic Charge:	$ 21.32
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.376 ¢ / kWh
Balance of kWh	@ 5.815 ¢ / kWh
Minimum Bill:	$ 21.32

COOKING AND HEATING SEASONAL - *TARIFF NO. 2016-24*

Annual Basic Charge:	$ 255.84
PLUS	
Energy Charge:	
First 66,000 kWh	@ 8.376 ¢ / kWh
Balance of kWh	@ 5.815 ¢ / kWh
Minimum Annual Bill:	$ 255.84

Seasonal Cooking and Heating accounts are billed twice a year, April and October, each for a six-month period. The April billing is for the Annual Basic Charge plus past winter season's consumption. The October billing is for the summer season's consumption only.

Applicability:

The General Service Cooking and Heating rate is applicable to services existing prior to April 1, 1976 for separately metered cooking, heating, process heating or car plug service in the same building or an extension of that building where the primary requirement is for General Service.

GENERAL SERVICE

DIESEL - *TARIFF NO. 2016-40*

Basic Charge:	$ 21.32
PLUS	
Energy Charge:	
First 2,000 kWh	@ 8.376 ¢ / kWh
Balance of kWh	@ 42.861 ¢ / kWh
Minimum Bill:	$ 21.32

The General Service rate applies to all commercial accounts excluding those classed as Government and /or First Nation Education.

GOVERNMENT AND FIRST NATION EDUCATION - *TARIFF NO. 2016-41*

Basic Charge:	$ 21.32
PLUS	
Energy Charge:	@ $2.6086 / kWh
Minimum Bill:	$ 21.32

The First Nation Education rate is applicable to all Diesel First Nation facilities providing instructional services for members of the Diesel First Nations, including schools, teacherages and student residences.

GENERAL SERVICE

EXCEEDING 200 kVA

(Utility-Owned transformation)

MEDIUM - *TARIFF NO. 2016-30*

Basic Charge:	$ 31.73
PLUS	
Energy Charge:	
First 11,000 kWh	@ 8.376 ¢ / kWh
Next 8,500 kWh	@ 5.815 ¢ / kWh
Balance of kWh	@ 3.838 ¢ / kWh
PLUS	
* Demand Charge:	
First 50 kVA of Monthly Billing Demand	No Charge
Balance of Billing Demand	@ $ 9.82 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Applicability:

The General Service Medium rate is applicable to services where the registered demand exceeds 200 kVA and where the transformation is provided by the Corporation.

Customers who, by nature of their business, do not require service during the months of December, January, and February may qualify for the General Service Short-Term Power rate. For further details see page 16.

GENERAL SERVICE

(Customer-Owned Transformation)

LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2016-60*

Energy Charge:		@ 3.609 ¢ / kWh
PLUS		
* Demand Charge:		@ $ 8.34 / kVA

Minimum Bill: Demand Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2016-61*

Energy Charge:	On-Peak Winter	@ 5.90 ¢ / kWh
	On-Peak Non-Winter	@ 4.86 ¢ / kWh
	Off-Peak	@ 2.70 ¢ / kWh
PLUS		
** Demand Charge:		@ $4.64 / kVA

Minimum Bill: Demand Charge

LARGE EXCEEDING 100 KV - *TARIFF NO. 2016-62*

Energy Charge:	On-Peak Winter	@ 5.70 ¢ / kWh
	On-Peak Non-Winter	@ 4.70 ¢ / kWh
	Off-Peak	@ 2.60 ¢ / kWh
PLUS		
** Demand Charge:		@ $3.50 / kVA

Minimum Bill: Demand Charge

Energy Charge

On-Peak hours are defined as all hours between 6:00 A.M. to 10:00 P.M. Monday to Friday inclusive excluding statutory holidays.

Off-Peak hours are all hours not considered on-peak hours.

The Winter season includes the months of December to March inclusive.

The Non-Winter season includes all months April to November inclusive.

Monthly Billing Demand **

The greatest of the following (expressed in kVA):

a) on-peak measured demand; or
b) 50% of contract demand; or
c) 50% of the highest measured on-peak demand in the previous 12 months

Applicability:

The General Service Large rate is applicable to services where the transformation is provided by the customer and connected directly to the Corporation's distribution, subtransmission or transmission lines.

Customers who, by nature of their business, do not require service during the months of December, January and February may qualify for the General Service Short-Term Power rate.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

0 TO NOT EXCEEDING 200 kVA

(Utility-Owned Transformation)

LUBD SMALL SINGLE PHASE - *TARIFF NO. 2016-50*

Basic Charge:	$ 21.32
PLUS	
Energy Charge:	@ 9.502¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.46 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge:

LUBD SMALL THREE PHASE - *TARIFF NO. 2016-51*

Basic Charge:	$ 30.06
PLUS	
Energy Charge:	@ 9.502 ¢ / kWh
PLUS	
Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.46 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge:

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Eligibility:

Any customer eligible for service on the General Service Small rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Small rates.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

EXCEEDING 200 kVA

(Utility-Owned Transformation)

LUBD MEDIUM - *TARIFF NO. 2016-52*

Basic Charge:	$ 31.73
PLUS	
Energy Charge:	@ 9.502 ¢ / kWh
PLUS	
* Demand Charge:	
First 50 kVA of Monthly Recorded Demand	No Charge
Balance of Recorded Demand	@ $ 2.46 / kVA

Minimum Bill:
Demand Charge PLUS Basic Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25% of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Primary metering of multiple Utility-Owned transformation services has an additional 2% added to the kVA for each transformation greater than one. There is also a 1% reduction on recorded demand and energy to account for transformer losses.

Eligibility:

Any customer eligible for service on the General Service Medium rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Medium rates.

GENERAL SERVICE LIMITED USE OF BILLING DEMAND RATE OPTION

(Customer-Owned Transformation)

LUBD LARGE 750 V TO NOT EXCEEDING 30 KV - *TARIFF NO. 2016-53*

Energy Charge:	@ 8.417 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 2.09 / kVA

Minimum Bill: Demand Charge

LUBD LARGE 30 KV TO NOT EXCEEDING 100 KV - *TARIFF NO. 2016-54*

Energy Charge:	@ 7.471 ¢ / kWh
PLUS	
* Demand Charge:	@ $ 1.79 / kVA

Minimum Bill: Demand Charge

LUBD LARGE EXCEEDING 100 KV - *TARIFF NO. 2016-55*

Energy Charge:	@ 6.914¢ / kWh
PLUS	
* Demand Charge:	@ $ 1.59 / kVA

Minimum Bill: Demand Charge

Monthly Billing Demand *

The greatest of the following (expressed in kVA):

a) measured demand; or
b) 25 % of contract demand; or
c) 25% of the highest measured demand in the previous 12 months.

Eligibility:

Any customer eligible for service on the General Service Large rate can request billing on this option, except customers who have been billed on this option during the 12 months prior to their request, but subsequently reverted to billing at regular General Service Large rates.

GENERAL SERVICE

FLAT RATE WATER HEATING RATES

(NOT available for new services)

TARIFF NO. 2016-29

Element Size	Uncontrolled
500 W	$ 17.28
600 W	$ 20.67
750 W	$ 25.79
1,000 W	$ 34.67
1,200 W	$ 41.48
1,500 W	$ 51.60
2,000 W	$ 64.69
2,500 W	$ 77.79
3,000 W	$ 90.51
3,500 W	$ 103.23
3,800 W	$ 114.11
4,000 W	$ 115.97
4,500 W	$ 128.70
5,000 W	$ 141.42
6,000 W	$ 166.88
6,500 W	$ 184.77
7,000 W	$ 192.31
7,500 W	$ 210.94
8,000 W	$ 217.75
9,000 W	$ 243.19
10,000 W	$ 268.67
10,500 W	$ 281.44
12,000 W	$ 319.59
12,500 W	$ 332.33
13,000 W	$ 345.06
13,500 W	$ 357.64
14,500 W	$ 383.10
15,000 W	$ 395.94
16,000 W	$ 421.39
16,500 W	$ 446.56
18,000 W	$ 472.36
19,000 W	$ 511.93
20,000 W	$ 523.23
23,000 W	$ 616.68
24,000 W	$ 642.90
25,000 W	$ 650.42
3,000 / 1,000 W	$ 42.23
2,000 / 1,500 W	$ 53.47
3,000 / 1,500 W	$ 54.06
4,500 / 1,500 W	$ 55.38

GENERAL SERVICE

Short-Term Power Rate

The General Service Short-Term application is available throughout the Province of Manitoba except in the Diesel Zone, for customers with services exceeding 200 kVA who, by the nature of their business, do not require service during the months of December, January, and February. Qualifying customers will be billed at, and subject to the conditions of, the appropriate General Service Medium or Large rate.

Services must be disconnected from 00:00 hours, December 1 to 24:00 hours, February 28/29. Customers may use up to a maximum of 1,000 kWh during these months for security purposes only (i.e. alarm system, security lighting) but must notify Manitoba Hydro each year in advance of their operation shutdown.

Service must be taken for a minimum of four months, normally consecutively, during the period March 1 to November 30. Customers will be subject to the same 25% ratchet provisions as applicable to General Service Medium and Large customers, with the exception that no ratchets will apply for the months of December, January or February unless the customer exceeds the 1,000 kWh per month allowable use during those months.

General Service Short-Term is NOT available in conjunction with other services at the same point of delivery.

Unmetered Services

Billed on the General Service Small Rate Tariff No. 2016-20 or 2016-21:

The Unmetered Service rate is applicable:

a) for non-residential customers where the load is constant and the consumption is consistent and metering is unnecessary or undesirable, specifically including traffic signals, pedestrian walkway lighting, directional traffic signs, hazard flashers, cable television power amplifiers, telephone booths, transit shelters (both heated and unheated), cathodic protection rectifiers (for oil and natural gas pipelines), water gauge wells, highway traffic counters, governmental navigational lights (both nautical and aerial), municipal sirens and Canadian Emergency Measures Organization emergency siren alarms.

b) for existing railway crossings, sign lighting and window lighting. Customers will be required to provide metering facilities if additional load is connected.

c) for services such as fairs, summer midways, television production and welding schools where service is required for less than 30 days.

d) for oil field pumping services connected prior to April 1, 1980 with oil pumping motors of the counter balanced (nodding or piston) type.

GENERAL SERVICE

SHORT-DURATION, INTERMITTENT RATE

TERMS AND CONDITIONS

General

Manitoba Hydro will supply short-duration, intermittent power and energy to customers whose operation requires short periods of high demand combined with overall, very low energy consumption.

The Corporation may regulate timing of the customer's demand requirements so that they do not coincide with other system peak demands.

The Corporation may interrupt the supply at any time, for any length of time and for any reason.

Conditions of Service

Qualifying customers will be billed at, and subject to the conditions of, the appropriate General Service Large or Medium rate with the following provisions:

a) Measured demand will be reduced by 50% for billing purposes.

b) Customers will be assessed a monthly energy entitlement based on a 1% load factor (monthly demand x 0.01 x 730) to be billed at the applicable General Service rate.

c) Energy consumption in excess of the monthly energy entitlement will be billed at a rate equal to 10 times the usual applicable General Service rate.

Customers will be required to enter into a formal contract with Manitoba Hydro. The contract will document the above conditions as well as any others considered necessary due to the nature of a specific service.

Rate Application

The General Service Short-Term, Intermittent rate is available to all customers, except those in the Diesel Rate Zone, to customers qualifying for the General Service Large and General Service Medium rates.

AREA AND ROADWAY LIGHTING

OUTDOOR LIGHTING

LEGEND

I	Incandescent
F	Fluorescent
CF	Compact Fluorescent
LED	Light Emitting Diode
MH	Metal Halide
MV	Mercury Vapour
HPS	High Pressure Sodium Vapour
Q	Quartz

Exclusive Pole: A corporate-owned pole for the primary purpose of supporting outdoor lighting devices.

Shared Pole: A pole of the primary purpose of supporting electrical circuits other than outdoor lighting.

AREA AND ROADWAY LIGHTING

(Incandescent and Mercury Vapour are NOT available for new installations)

OUTDOOR LIGHTING RATE - *TARIFF NO. 2016-80:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
200 F	-	$ 10.73
20 CF	-	$ 2.30
100 I	$ 4.94	$ 10.73
150 I	-	$ 10.73
300 I	-	$ 15.30
500 I	$ 12.92	$ 21.08
400 MH	-	$ 25.69
175 MV	$ 9.55	$ 15.30
250 MV	$ 10.94	$ 17.32
400 MV	$ 15.00	$ 20.72
70 HPS	$ 8.21	$ 13.48
70 HPS 24 hours	-	$ 15.16
100 HPS	$ 8.52	$ 14.22
150 HPS	$ 10.45	$ 16.06
250 HPS	$ 13.32	$ 18.51
400 HPS	$ 15.28	$ 25.69
400 HPS 2/100'	-	$ 39.71
400 HPS 4/100'	-	$ 29.17
750 HPS	$ 23.68	$ 37.56
1 000 HPS	-	$ 43.57
1 000 HPS 1/60'	-	$ 44.57
1 000 HPS 2/100'	-	$ 53.42
1 000 HPS 4/100'	-	$ 45.81
10 LED (1 – 30 W)	-	$ 2.10
40 LED (> 30 – 50 W)	$ 7.06	$ 12.33
40 LED 24 hr (> 30 – 50 W)	-	$ 14.01
60 LED (> 50 – 80 W)	$ 7.20	$ 12.90
90 LED (> 80 – 120 W)	$ 8.63	$ 14.24
150 LED (> 120 – 180 W)	$ 10.28	$ 15.47
250 LED (> 180 – 280 W)	$ 10.42	$ 20.83
250 LED 2/100' (> 180 – 280 W)	-	$ 34.85
250 LED 4/100' (> 180 – 280 W)	-	$ 24.31

Applicability:

The Area and Roadway rate is available throughout the Province of Manitoba and applies to area and roadway lighting installed by agreement for public authorities.

AREA AND ROADWAY LIGHTING

(NOT available for new installations)

FLOOD LIGHTING RATE - *TARIFF NO. 2016-81:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	Exclusive Pole/Luminaire
100 I	$ 5.59	-
150 I	$ 5.59	$ 11.60
300 I	$ 10.20	-
500 I	$ 13.73	$ 22.47
250 MV	$ 12.64	$ 18.49
400 MV	$ 15.45	$ 20.75
500 Q	$ 21.24	$ 26.91

Applicability:

The Floodlighting rate is applicable for floodlighting services existing prior to April 1, 1976 for lighting of public buildings, structures, monuments, parks, grounds and Department of Highways overhead signs served from the Corporation distribution system where the Corporation owns and maintains the luminaires.

AREA AND ROADWAY LIGHTING

SEASONAL RATE - *TARIFF NO. 2016-82:*

Watts	Rate Per Month	
	Shared Pole/Luminaire	**Exclusive Pole/Luminaire**
70 HPS	$ 8.21	$ 13.48
100 HPS	$ 8.52	$ 14.22
150 HPS	$ 10.45	$ 16.06
250 HPS	$ 13.32	$ 18.51

Applicability:

The Seasonal Area and Roadway Lighting rate is available only outside the City of Winnipeg and is applicable for area and roadway lighting installed by agreement for Municipal Corporation, local government districts, Provincial and Federal Governments.

Lighting will be energized from May 1 to October 31 of each year and will be disconnected from November 1 to April 30.

AREA AND ROADWAY LIGHTING

SENTINEL LIGHTING RATE - *TARIFF NO. 2016-83:*

Watts	Rate Per Month	
	Flat Rate (Energy and Rental)	Metered (Rental Only)
100 HPS	$ 10.54	$ 7.29
150 HPS	$ 14.00	$ 9.95
175 MV	$ 10.91	$ 7.27
400 MV	$ 18.06	$ 9.95

Applicability:

Sentinel lighting is available for security lighting of private or public areas on a dusk-to-dawn basis throughout the Province of Manitoba. Rental units are intended for continuous year-round service and are not provided on a temporary basis.

Sentinel lighting is available for rental as follows:

a) on a flat rate basis when connected directly to the Manitoba Hydro distribution system; or
b) exclusive of electricity if connected to the customer's metered circuits.

AREA AND ROADWAY LIGHTING

FESTOON LIGHTING - *TARIFF NO. 2016-84*

Connected load @ $0.942/ kW per night of scheduled use:

Minimum Monthly Bill: $ 19.23

Applicability:

The Festoon Lighting rate is applicable only for existing unmetered municipally-owned festoon light strings suspended across streets and public thoroughfares. The customer is required to advise the Corporation prior to any changes in the nights contract for operation and/or the connected lighting kilowatts.

DECORATIVE LIGHTING - *TARIFF NO. 2016-85*

Connected load @ $0.942/kW per night of scheduled use:

Minimum Monthly Bill: $ 19.23

Applicability:

The Decorative Lighting rate is applicable for new and existing unmetered municipally-owned decorative lights on frames or modules mounted on roadway lighting poles or ornamental standards and/or Christmas trees. The customer is required to advise the Corporation prior to any change in the nights contracted for operation and\or the connected lighting kilowatts.

CHRISTMAS LIGHTING - *TARIFF NO. 2016-86*

Connected load @ $0.0752/ kWh.

Applicability:

The Christmas Lighting rate is applicable to the City of Winnipeg Christmas lighting only. The customer is required to advise the Corporation prior to any change in the connected load.

BILL COMPARISONS

MAY 1, 2014 RATES

VS

PROPOSED
APRIL 1, 2015 RATES

Manitoba Hydro

Bill Comparison

Residential

Forecast Customers: 473,761

kWh	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
250	$25.73	$26.75	$1.02	3.96%
750	$62.64	$65.11	$2.47	3.94%
1 000	$81.09	$84.29	$3.20	3.95%
2 000	$154.90	$161.01	$6.11	3.94%
5 000	$376.33	$391.17	$14.84	3.94%

Residential Seasonal

Forecast Customers: 20,914

kWh	May 1, 2014 $ / Summer	April 1, 2015 $ / Summer	Difference in $ / Summer	Percent Change
250	$105.81	$110.02	$4.21	3.98%
750	$142.72	$148.38	$5.66	3.97%
1 000	$161.17	$167.56	$6.39	3.96%
2 000	$234.98	$244.28	$9.30	3.96%
5 000	$456.41	$474.44	$18.03	3.95%

Residential Diesel

Forecast Customers: 595

kWh	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
250	$25.73	$26.75	$1.02	3.96%
750	$62.64	$65.11	$2.47	3.94%
1 000	$81.09	$84.29	$3.20	3.95%
2 000	$154.90	$161.01	$6.11	3.94%
5 000	$376.33	$391.17	$14.84	3.94%

Bill Comparison

General Service Small
< 50 kVA

Forecast Customers: 53,207

kWh	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
750	$77.87	$80.95	$3.08	3.96%
2 000	$174.77	$181.67	$6.90	3.95%
5 000	$407.33	$423.41	$16.08	3.95%
10 000	$794.93	$826.31	$31.38	3.95%

General Service Small
51 kVA

Forecast Customers: 12,026

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$758.47	$788.41	$29.94	3.95%
50%	$1,299.39	$1,350.73	$51.34	3.95%
75%	$1,646.20	$1,711.22	$65.02	3.95%
100%	$1,976.79	$2,054.83	$78.04	3.95%

General Service Small
100 kVA

Forecast Customers: 12,026

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$1,725.16	$1,793.37	$68.21	3.95%
50%	$2,396.27	$2,490.93	$94.66	3.95%
75%	$3,044.51	$3,164.72	$120.21	3.95%
100%	$3,692.75	$3,838.51	$145.76	3.95%

Bill Comparison

General Service
Seasonal

Forecast Customers: 876

kWh	May 1, 2014 $ / Summer	April 1, 2015 $ / Summer	Difference in $ / Summer	Percent Change
750	$294.90	$306.56	$11.66	3.95%
2 000	$391.80	$407.28	$15.48	3.95%
5 000	$624.36	$649.02	$24.66	3.95%
10 000	$1,011.96	$1,051.92	$39.96	3.95%

General Service
Diesel

Forecast Customers: 115

kWh	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
750	$77.87	$80.95	$3.08	3.96%
2 000	$174.77	$181.67	$6.90	3.95%
5 000	$1,364.72	$1,418.63	$53.91	3.95%
10 000	$3,347.97	$3,480.23	$132.26	3.95%

General Service
Government and First Nation Education

Forecast Customers: 67

kWh	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
750	$1,830	$1,903	$72	3.95%
2 000	$4,848	$5,040	$192	3.95%
5 000	$12,090	$12,568	$478	3.95%
10 000	$24,161	$25,116	$955	3.95%

Bill Comparison

General Service Medium
500 kVA

Forecast Customers: 2,026

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$7,979	$8,294	$315	3.95%
50%	$11,220	$11,663	$443	3.95%
75%	$14,461	$15,032	$571	3.95%
100%	$17,702	$18,401	$699	3.95%

General Service Medium
1 000 kVA

Forecast Customers: 2,026

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$15,765	$16,388	$623	3.95%
50%	$22,247	$23,126	$879	3.95%
75%	$28,730	$29,864	$1,134	3.95%
100%	$35,212	$36,602	$1,390	3.95%

Bill Comparison

General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 313

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$69,068	$71,782	$2,714	3.93%
50%	$99,537	$103,464	$3,927	3.95%
75%	$130,005	$135,146	$5,141	3.95%
100%	$160,474	$166,828	$6,354	3.96%

General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 40

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$122,766	$127,611	$4,845	3.95%
50%	$179,433	$186,522	$7,089	3.95%
75%	$236,099	$245,433	$9,334	3.95%
100%	$292,765	$304,344	$11,579	3.96%

General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 13

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
25%	$568,571	$590,930	$22,359	3.93%
50%	$843,143	$876,360	$33,217	3.94%
75%	$1,117,714	$1,161,790	$44,076	3.94%
100%	$1,392,285	$1,447,220	$54,935	3.95%

Bill Comparison

Limited Use Billing Demand - General Service Small
100 kVA

Forecast Customers: 53

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
5%	$462.34	$480.75	$18.41	3.98%
10%	$783.36	$814.58	$31.22	3.99%
15%	$1,104.37	$1,148.41	$44.04	3.99%
20%	$1,425.39	$1,482.24	$56.85	3.99%

Limited Use Billing Demand - General Service Medium
500 kVA

Forecast Customers: 16

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
5%	$2,655.95	$2,761.67	$105.72	3.98%
10%	$4,261.04	$4,430.81	$169.77	3.98%
15%	$5,866.12	$6,099.96	$233.84	3.99%
20%	$7,471.21	$7,769.10	$297.89	3.99%

Bill Comparison

Limited Use Billing Demand - General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 3

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
5%	$23,863	$24,823	$960	4.02%
10%	$38,076	$39,597	$1,521	3.99%
15%	$52,289	$54,370	$2,081	3.98%
20%	$66,502	$69,144	$2,642	3.97%

Limited Use Billing Demand - General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 0

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
5%	$41,740	$43,444	$1,704	4.08%
10%	$66,980	$69,687	$2,707	4.04%
15%	$92,219	$95,931	$3,712	4.03%
20%	$117,459	$122,174	$4,715	4.01%

Limited Use Billing Demand - General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 3

Load Factor	May 1, 2014 $ / Month	April 1, 2015 $ / Month	Difference in $ / Month	Percent Change
5%	$191,453	$197,917	$6,464	3.38%
10%	$307,907	$319,335	$11,428	3.71%
15%	$424,360	$440,752	$16,392	3.86%
20%	$540,813	$562,169	$21,356	3.95%

BILL COMPARISONS

PROPOSED

APRIL 1, 2015 RATES

VS

PROPOSED

APRIL 1, 2016 RATES

Manitoba Hydro

Bill Comparison

Residential

Forecast Customers: 479,963

kWh	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
250	$26.75	$27.81	$1.06	3.96%
750	$65.11	$67.68	$2.57	3.95%
1 000	$84.29	$87.62	$3.33	3.95%
2 000	$161.01	$167.37	$6.36	3.95%
5 000	$391.17	$406.62	$15.45	3.95%

Residential Seasonal

Forecast Customers: 21,014

kWh	April 1, 2015 $ / Summer	April 1, 2016 $ / Summer	Difference in $ / Summer	Percent Change
250	$110.02	$114.38	$4.36	3.96%
750	$148.38	$154.25	$5.87	3.96%
1 000	$167.56	$174.19	$6.63	3.96%
2 000	$244.28	$253.94	$9.66	3.95%
5 000	$474.44	$493.19	$18.75	3.95%

Residential Diesel

Forecast Customers: 603

kWh	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
250	$26.75	$27.81	$1.06	3.96%
750	$65.11	$67.68	$2.57	3.95%
1 000	$84.29	$87.62	$3.33	3.95%
2 000	$161.01	$167.37	$6.36	3.95%
5 000	$391.17	$406.62	$15.45	3.95%

Bill Comparison

General Service Small
< 50 kVA

Forecast Customers: 53,676

kWh	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
750	$80.95	$84.14	$3.19	3.94%
2 000	$181.67	$188.84	$7.17	3.95%
5 000	$423.41	$440.12	$16.71	3.95%
10 000	$826.31	$858.92	$32.61	3.95%

General Service Small
51 kVA

Forecast Customers: 12,125

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$788.41	$819.52	$31.11	3.95%
50%	$1,350.73	$1,404.05	$53.32	3.95%
75%	$1,711.22	$1,778.79	$67.57	3.95%
100%	$2,054.83	$2,136.00	$81.17	3.95%

General Service Small
100 kVA

Forecast Customers: 12,125

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$1,793.37	$1,864.01	$70.64	3.94%
50%	$2,490.93	$2,589.16	$98.23	3.94%
75%	$3,164.72	$3,289.60	$124.88	3.95%
100%	$3,838.51	$3,990.03	$151.52	3.95%

Bill Comparison

General Service
Seasonal

Forecast Customers: 881

kWh	April 1, 2015 $ / Summer	April 1, 2016 $ / Summer	Difference in $ / Summer	Percent Change
750	$306.56	$318.66	$12.10	3.95%
2 000	$407.28	$423.36	$16.08	3.95%
5 000	$649.02	$674.64	$25.62	3.95%
10 000	$1,051.92	$1,093.44	$41.52	3.95%

General Service
Diesel

Forecast Customers: 117

kWh	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
750	$80.95	$84.14	$3.19	3.94%
2 000	$181.67	$188.84	$7.17	3.95%
5 000	$1,418.63	$1,474.67	$56.04	3.95%
10 000	$3,480.23	$3,617.72	$137.49	3.95%

General Service
Government and First Nation Education

Forecast Customers: 67

kWh	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
750	$1,903	$1,978	$75	3.95%
2 000	$5,040	$5,239	$199	3.95%
5 000	$12,568	$13,064	$496	3.95%
10 000	$25,116	$26,107	$992	3.95%

Bill Comparison

General Service Medium
500 kVA

Forecast Customers: 2,046

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$8,294	$8,620	$326	3.93%
50%	$11,663	$12,122	$459	3.94%
75%	$15,032	$15,624	$592	3.94%
100%	$18,401	$19,127	$726	3.95%

General Service Medium
1 000 kVA

Forecast Customers: 2,046

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$16,388	$17,032	$644	3.93%
50%	$23,126	$24,037	$911	3.94%
75%	$29,864	$31,041	$1,177	3.94%
100%	$36,602	$38,045	$1,443	3.94%

General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 320

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$71,782	$74,632	$2,850	3.97%
50%	$103,464	$107,564	$4,100	3.96%
75%	$135,146	$140,496	$5,350	3.96%
100%	$166,828	$173,429	$6,601	3.96%

Bill Comparison

Bill comparisons for the Large >30 kV customer classes incorporate the proposed Time of Use (TOU) rates to be effective April 1, 2016. For each of the four Load Factor levels, distribution of the energy usage between the four pricing periods (peak, off-peak, winter, non-winter) is based on the overall class average percentages for each of these pricing periods. The impact on individual customers however will vary dependent on their load factor and distribution of their energy use amongst the pricing periods.

The following two tables compare the proposed April 2015 rates to the proposed April 2016 TOU rates. The differences and percentages shown reflect both the 3.95% rate increase as well as the impact of the change in rate design.

General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 41

Load Factor	Standard April 1, 2015 $ / Month	TOU April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$127,611	$116,061	($11,550)	-9.05%
50%	$186,522	$185,722	($800)	-0.43%
75%	$245,433	$255,383	$9,950	4.05%
100%	$304,344	$325,044	$20,700	6.80%

General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 13

Load Factor	Standard April 1, 2015 $ / Month	TOU April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$590,930	$513,820	($77,110)	-13.05%
50%	$876,360	$852,641	($23,719)	-2.71%
75%	$1,161,790	$1,191,461	$29,671	2.55%
100%	$1,447,220	$1,530,282	$83,062	5.74%

Bill Comparison

The following two tables compare the impact of the April 1, 2016 TOU rates exclusive of the 3.95% rate increase to better depict the impact of the change in rate design.

General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 41

Load Factor	Standard April 1, 2016 $ / Month	TOU April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$132,647	$116,061	($16,586)	-12.50%
50%	$193,894	$185,722	($8,172)	-4.21%
75%	$255,141	$255,383	$242	0.09%
100%	$316,388	$325,044	$8,656	2.74%

General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 13

Load Factor	Standard April 1, 2016 $ / Month	TOU April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
25%	$614,245	$513,820	($100,425)	-16.35%
50%	$910,990	$852,641	($58,349)	-6.41%
75%	$1,207,735	$1,191,461	($16,274)	-1.35%
100%	$1,504,480	$1,530,282	$25,802	1.71%

Bill Comparison

Limited Use Billing Demand - General Service Small
100 kVA

Forecast Customers: 54

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
5%	$480.75	$499.88	$19.13	3.98%
10%	$814.58	$846.71	$32.13	3.94%
15%	$1,148.41	$1,193.53	$45.12	3.93%
20%	$1,482.24	$1,540.35	$58.11	3.92%

Limited Use Billing Demand - General Service Medium
500 kVA

Forecast Customers: 17

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
5%	$2,761.67	$2,872.85	$111.18	4.03%
10%	$4,430.81	$4,606.96	$176.15	3.98%
15%	$6,099.96	$6,341.08	$241.12	3.95%
20%	$7,769.10	$8,075.19	$306.09	3.94%

Bill Comparison

Limited Use Billing Demand - General Service Large - 750 V to 30 kV
5 000 kVA

Forecast Customers: 3

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
5%	$24,823	$25,811	$988	3.98%
10%	$39,597	$41,172	$1,575	3.98%
15%	$54,370	$56,533	$2,163	3.98%
20%	$69,144	$71,894	$2,750	3.98%

Limited Use Billing Demand - General Service Large - 30 kV to 100 kV
10 000 kVA

Forecast Customers: 0

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
5%	$43,444	$45,169	$1,725	3.97%
10%	$69,687	$72,438	$2,751	3.95%
15%	$95,931	$99,707	$3,776	3.94%
20%	$122,174	$126,977	$4,803	3.93%

Limited Use Billing Demand - General Service Large - Over 100 kV
50 000 kVA

Forecast Customers: 3

Load Factor	April 1, 2015 $ / Month	April 1, 2016 $ / Month	Difference in $ / Month	Percent Change
5%	$197,917	$205,681	$7,764	3.92%
10%	$319,335	$331,861	$12,526	3.92%
15%	$440,752	$458,042	$17,290	3.92%
20%	$562,169	$584,222	$22,053	3.92%

Appendix 6.7
January 23, 2015

SURPLUS ENERGY PROGRAM

PROPOSED TERMS AND CONDITIONS

Manitoba Hydro

SURPLUS ENERGY PROGRAM
INDUSTRIAL LOAD - OPTION 1
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Schedules

SURPLUS ENERGY PROGRAM
INDUSTRIAL LOAD - OPTION 1
TERMS AND CONDITIONS

ELIGIBILITY

1. SEP - Option 1 is available to industrial loads which meet the following qualifications:

   a) Total Demand must be 1 000 kVA or greater. Total Demand is defined as the Reference Level of Demand (as described in Section 3 below) **plus** the level of Demand associated with SEP; and

   b) Demand associated with SEP does not exceed 50 MVA **except** where the load factor of such load is guaranteed by the customer, in writing, to exceed 25% on a weekly basis; and

   c) Are not being served under the Curtailable Rate Program; and

   d) Manitoba Hydro may require a customer to maintain a minimum Power Factor of 90% as a condition of participation.

REFERENCE DEMAND

2. A customer shall designate a Reference Level of Demand (both in kV.A and kW) for each calendar month of the year. Customers have the option of designating different Reference Demands for each TOU periods (Peak, Shoulder, Off-Peak). The Reference Demand is subject to the following:

   a) The designation must be made prior to participation in SEP; and

   b) The Reference Level of Demand must equal at least 75% of Total Demand

      - *Exception*: Manitoba Hydro may allow exceptions to the 75% qualification, where a customer can demonstrate, to the satisfaction of Manitoba Hydro, that it has on-site back-up capability in the form of a generating facility or alternative equipment capable of supporting the process to which SEP is applied and, that, the back-up capability together with the Reference Level of Demand can supply 75% or more of the Total Demand; and

3. Subject to Subsections 3 b) and c), a customer may increase its designated Reference Level of Demand or may convert part or all of the load served under SEP to firm service by providing Manitoba Hydro with advance written notice based on the following notice period options, of which, must be determined and designated on Schedule ‘A’ of the customer’s SEP contract prior to participation in SEP. In all cases Manitoba Hydro may reduce the notice period if, in its sole discretion such reduction can be accomplished without adverse impact to the operations or revenues of the corporation.

a) A 12 month notice period with an option of:

   i) the customer will pay a premium of 1.0¢ per kWh for energy purchased during the summer peak hours; or

   ii) the customer will agree that load converted on 12 months notice shall be subject to curtailment under the provisions of Option "A" or "R" of the Curtailable Rate Program for the first four months following the conversion; or

b) A notice period dependent on when the said notice is provided, as follows:

   i) where notice is provided between September 1 up to and including January 31, a 12 month notice period shall apply; or

   ii) where notice is provided between February 1 up to and including April 30, a 16 month notice period shall apply. Where the customer provides notice between February 1 and April 30, the customer may elect at the time notice is given, to convert to the notice provisions outlined in Subsection 4 a) ii) above; or

   iii) where notice is provided between May 1 up to and including August 31, the notice period shall not expire prior to August 31 of the following year such that notice will be not greater than 16 months or less than 12 months. Where the customer provides notice between May 1 and August 1, the customer may elect, at the time notice is given, to convert to the notice provisions outlined in Subsection 4 a) ii) above.

BILLING

4. Energy Charges:

SEP energy is energy associated with the demand taken by a customer in excess of the monthly Reference Level of Demand(s) (in kW). Measurement of SEP energy will be based on each 15-minute interval reading of kW during a billing month.

Rates to SEP - Option 1 customers will be set as follows. The rates which will be charged are set out in Schedule SEP-1 (attached) and are subject to weekly approval by the PUB as per Schedule SEP-2 (attached).

a) i) a Basic Charge of $100.00 per month to cover administration and metering costs;

   ii) an Energy Charge per kWh which will be set for three Time-of-Use periods on a weekly basis; that is, one for each of the peak, shoulder, and off-peak periods. The periods are defined below:

	Summer (May 1 - October 31)	**Winter (November 1 - April 30)**
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

The Weekly Energy Charge will be determined as per Schedule SEP-3 (attached).

iii) a Distribution Charge per kWh intended to collect approximately one-third of the embedded cost of distribution, subtransmission, and regional transmission.

b) All non-SEP energy will be billed at the appropriate standard General Service Large or Medium rate.

5. Demand Charge:

a) The demand up to the maximum monthly Reference Level of Demand in kV.A will be billed at the at the appropriate standard General Service Large or Medium rate, subject to Monthly Billing Demand criteria as set out in Subsection 6 b). In the case of different Reference Level of Demand for the TOU periods, the highest designated monthly TOU Reference Level of Demand will be used.

b) The Monthly Billing Demand in KV.A for a customer participating in SEP is the greatest of the following:

i) measured demand up to a maximum of the monthly Reference Level of Demand in kVA; or

ii) 25% of the highest annual Reference Level of Demand in kV.A

- *Exception:* In the event that a customer's demand exceeds Total Demand as defined in Subsection 2 a), the appropriate standard General Service Large or Medium Demand Charge will apply to all kVA in excess of Total Demand. The Reference Level of Demand plus the demand in excess of Total Demand will be used in determining the Monthly Billing Demand. Manitoba Hydro does not guarantee the supply of firm capacity in excess of the Reference Level of Demand.

INTERRUPTIONS

6. On notice by fax/email or phone from Manitoba Hydro, a customer will be required to reduce its load within 36 hours to its Reference Level of Demand(s) (kW) in one or more of the TOU periods as specified in the notice, and to maintain its load at or below its Reference Level of Demand(s) in the specified period(s) until notified by Hydro by fax/email or phone that the interruption is ended.

   Where the SEP load is separately metered, the customer will be required to interrupt supply to the SEP load.

7. Failure to reduce load to or below the Reference Level of Demand (kW) during an interruption can result in additional charges based on the actual costs Manitoba Hydro incurs to supply any load above the Reference Level of Demand. The maximum additional charge is $150.00 per kW of Demand and $1.00 per kWh of associated energy.

8. A customer will be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra-provincially.

METERING AND ELECTRIC SERVICE FACILITIES

9. Manitoba Hydro will supply the appropriate metering for a SEP customer.

10. The customer shall be responsible for all costs of building or upgrading regional transmission, subtransmission, distribution and/or dedicated services which may be required to serve SEP load.

CONTRACT REQUIREMENTS

11. A customer will be required to enter into a formal agreement with Manitoba Hydro. The agreement will document the above Terms and Conditions as well as any others considered necessary due to the nature of a specific service.

CUSTOMER WAIVER – NO BACK-UP FACILITIES REQUIRED

12. Where no back-up facilities are required as per Subsection 3 b), a customer will be required to sign a waiver stating that:

    a) The customer has included in its Reference Level of Demand sufficient kV.A/kW for all essential load within its operation.

    b) The customer understands that the Terms and Conditions of SEP provide for:

       i) SEP energy prices-per-kWh which can be volatile from week-to-week, and can be extremely high during periods of scarcity in interconnected markets; and

ii) interruption in the supply of SEP energy can be initiated by Manitoba Hydro on 36 hours notice to the customer for any reason; and

iii) possible lengthy periods of interruption.

c) The customer has considered the implications of the foregoing and will comply without objection to interruptions made in accordance with the Terms and Conditions of SEP.

CUSTOMER WAIVER – BACK-UP FACILITIES REQUIRED

13. Where back-up facilities are required as per Subsection 3 b):

a) A customer will be required to sign a waiver as per Subsections 13 b) and c).

b) The customer must provide certification in writing to Manitoba Hydro that:

i) the back-up facility is adequate to serve that portion of SEP load in excess of 25% of Total Demand, given the type of load and possibly lengthy interruption of SEP supply; and

ii) the installation and operation of the back-up facility complies with all government regulations including all municipal and provincial zoning and environmental regulations.

c) Certification of back-up as described in Subsections 14 b) i) and ii) must be provided in writing to Manitoba Hydro when the customer first accepts SEP service and by no later than October 1, of every year thereafter that the customer is accepting SEP service.

d) If a customer ceases, or is unable to maintain an adequate back-up facility:

i) the customer must notify Manitoba Hydro in writing of the situation immediately; and

ii) the customer must reduce its Total Demand to the Reference Level of Demand(s); and

iii) should the customer continue to use SEP, Manitoba Hydro may bill the customer for Demand (kV.A) associated with SEP energy use at the applicable General Service Large or Medium Demand Charge for the period of time the back-up facility is considered to be, or to have been, inadequate; and

iv) notice to convert load served under SEP to firm service will be as set out in Section 4.

GENERAL SERVICE ALTERNATIVE RATES
SURPLUS ENERGY PROGRAM RATE

General Service-Medium (Utility-Owned Transformer)		**Tariff No. 50-19:**
Basic Monthly Charge:	$100.00	
PLUS		
Distribution Charge:	0.62¢/kWh	
PLUS		
Energy Charge:		
Peak Hours	________	
Shoulder Hours	________	
Off-Peak Hours	________	

General Service-Large 750 V to Not Exceeding 30 kV		**Tariff No. 50-20:**
Basic Monthly Charge:	$100.00	
PLUS		
Distribution Charge:	0.33¢/kWh	
PLUS		
Energy Charge:		
Peak Hours	________	
Shoulder Hours	________	
Off-Peak Hours	________	

General Service-Large 30 kV to Not Exceeding 100 kV		**Tariff No. 50-21:**
Basic Monthly Charge:	$100.00	
PLUS		
Distribution Charge:	0.14¢/kWh	
PLUS		
Energy Charge:		
Peak Hours	________	
Shoulder Hours	________	
Off-Peak Hours	________	

General Service-Large Exceeding 100 kV		**Tariff No. 50-22:**
Basic Monthly Charge:	$100.00	
PLUS		
Distribution Charge:	0.06¢/kWh	
PLUS		
Energy Charge:		
Peak Hours	________	
Shoulder Hours	________	
Off-Peak Hours	________	

Hours	Summer (May 1 - October 31)	Winter (November 1 - April 30)
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

SURPLUS ENERGY PROGRAM
PROCEDURE FOR INTERIM EX PARTE
PUBLIC UTILITIES BOARD (PUB) APPROVAL OF SEP RATE

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1. Each Wednesday by 9:00 AM Central Time (CT), Manitoba Hydro shall:

   i) email to the Board a copy of Schedule SEP-1 which shall include the Energy Charge for the Time-of-Use periods for all General Service Medium and Large classes of service;

   ii) indicate the expected source of SEP energy (i.e. from displaced exports, Manitoba Hydro generation, or imports); and

   iii) warrant that the price has been estimated using approved methodology as set out in Schedule SEP-3.

   The "Delivered Microsoft Outlook" message for the email will serve as confirmation that the PUB has received the schedule.

2. If Schedule SEP-1 is acceptable, the PUB will provide interim *ex parte* approval of the rates and email the Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT the same day. If the proposed Schedule, for any reason, is not acceptable, the PUB will contact Manitoba Hydro as soon as possible and attempt to resolve any concerns. If these concerns cannot be resolved by Wednesday at 3:00 PM CT, Manitoba Hydro will then forthwith contact customers to inform them that SEP energy is not available for the following week.

3. If the PUB emails an Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT on Wednesday, Manitoba Hydro shall fax/email the approved rate schedule to the SEP customers by 3:00 PM CT the same day.

4. Steps 1 through 3 shall be repeated each Wednesday that SEP energy is available.

SURPLUS ENERGY PROGRAM
PROCEDURE FOR DETERMINATION OF
WEEKLY ENERGY CHARGE

The SEP Energy Charge for each of the three Time-of-Use (TOU) periods shall be determined by Manitoba Hydro weekly, on a forecast basis for the following week (Monday through Sunday), as follows:

- If SEP energy displaces extra-provincial sales, the Energy Charge shall be such as to collect the revenue that would have been received from the foregone energy sales from the week to which the Energy Charge applies.

- If SEP energy is provided from purchased power, the Energy Charge shall be the amount necessary to recover the cost of the purchased power, including Transmission Service Charges, Administration Fees and Losses, plus 10% as a contribution to reserves.

- If SEP energy is provided from Manitoba Hydro generation, the Energy Charge shall be the amount necessary to collect the incremental cost of generation including Transmission Losses, plus 10% as a contribution to reserves. The latter is to administer energy and to cover a small share of fixed cost or contribution to reserves.

- In forecasting the weekly energy prices, Manitoba Hydro will consider what price experience has been under similar conditions of seasonality, expected demand and supply in the Midwest Independent Transmission System Operator (MISO) Market. An adder will be applied to each of the three TOU periods to account for market volatility or unforeseen supply costs. The adders will be adjusted as required to ensure a balance is maintained over the long-term between actual energy costs and revenues from SEP energy.

SURPLUS ENERGY PROGRAM
HEATING LOAD - OPTION 2

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SURPLUS ENERGY PROGRAM
HEATING LOAD - OPTION 2
TERMS AND CONDITIONS

ELIGIBILITY

1. SEP - Option 2 is available to heating loads which meet the following qualifications:

   a) Demand must be 200 kW or greater; and

   b) The electricity is to be used for space and/or water heating only; and

   c) The load must be metered separately from the customer's firm load; and

   d) The customer has an alternate energy source as a back-up facility for the entire SEP load; and

   e) Demand associated with SEP does not exceed 50 MVA **except** where the load factor of such load is guaranteed by the customer, in writing, to exceed 25% on a weekly basis; and

   f) The load is not being served under the Curtailable Rate Program.

CONVERSION TO FIRM SERVICE

2. A customer may convert part or all of the load served under SEP to firm service by providing Manitoba Hydro with advance written notice based on the following notice period options, of which, must be determined and designated on Schedule 'A' of the customer's SEP contract prior to participation in SEP. In all cases Manitoba Hydro may reduce the notice period if, in its sole discretion such reduction can be accomplished without adverse impact to the operations or revenues of the corporation.

   a) A 12 month notice period with an option of:

      i) the customer will pay a premium of 1.0¢ per kWh for energy purchased during the summer peak hours; or

      ii) the customer will agree that load converted on 12 months notice shall be subject to curtailment under the provisions of Option "A" or "R" of the Curtailable Rate Program for the first four months following the conversion; or

   b) A notice period dependent on when the said notice is provided, as follows:

      i) where notice is provided between September 1 up to and including January 31, a 12 month notice period shall apply; or

ii) where notice is provided between February 1 up to and including April 30, a 16 month notice period shall apply. Where the customer provides notice between February 1 and April 30, the customer may elect at the time notice is given, to convert to the notice provisions outlined in Subsection 3 a) ii) above; or

iii) where notice is provided between May 1 up to and including August 31, the notice period shall not expire prior to August 31 of the following year such that notice will be not greater than 16 months or less than 12 months. Where the customer provides notice between May 1 and August 1, the customer may elect, at the time notice is given, to convert to the notice provisions outlined in Subsection 3 a) ii) above.

BILLING

3. Rates to SEP - Option 2 customers will be set as follows. The rates which will be charged are set out in Schedule SEP-1 (attached) and are subject to weekly approval by the PUB as per Schedule SEP-2 (attached).

a) i) a Basic Charge to cover administration and metering costs as follows:

- For loads of 1 000 kV.A or greater $100.00 per month
- For loads of less than 1 000 kV.A $50.00 per month

ii) An Energy Charge per kWh which will be set for three Time-of-Use periods on a weekly basis; that is, one for each of the peak, shoulder, and off-peak periods. The periods are defined below:

	Summer (May 1 - October 31)	**Winter (November 1 - April 30)**
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

The Weekly Energy Charge will be determined as per Schedule SEP-3 (attached).

iii) a Distribution Charge per kWh intended to collect approximately one-third of the embedded cost of distribution, subtransmission, and regional transmission.

INTERRUPTIONS

4. On notice by fax/email or phone from Manitoba Hydro, a customer will be required to interrupt electricity supply to the SEP load within 36 hours in one or more of the TOU periods as specified in the notice, and may not resume use of SEP in the specified period(s) until notified by Hydro by fax/email or phone that the interruption is ended.

5. Failure to interrupt SEP load during an interruption can result in additional charges based on the actual costs Manitoba Hydro incurs to supply SEP load during an interruption. The maximum additional charge is $150.00 per kW of Demand and $1.00 per kWh of associated energy.

6. A customer will be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra-provincially.

METERING AND ELECTRIC SERVICE FACILITIES

7. Manitoba Hydro will supply the appropriate metering for a SEP customer.

8. The customer shall be responsible for all costs of building or upgrading regional transmission, subtransmission, distribution and/or dedicated services which may be required to serve SEP load.

CONTRACT REQUIREMENTS

9. A customer will be required to enter into a formal agreement with Manitoba Hydro. The agreement will document the above Terms and Conditions as well as any others considered necessary due to the nature of a specific service.

CUSTOMER WAIVER

10. a) A customer will be required to sign a waiver stating that the customer understands that the Terms and Conditions of SEP provide for:

    i) SEP energy prices-per-kWh which can be volatile from week-to-week, and can be extremely high during periods of scarcity in interconnected markets; and

    ii) interruption in the supply of SEP energy can be initiated by Manitoba Hydro on 36 hours notice to the customer for any reason; and

    iii) possible lengthy periods of interruption

    b) The customer has considered the implications of the foregoing and will comply without objection to interruptions made in accordance with the Terms and Conditions of SEP.

c) The customer must provide certification in writing to Manitoba Hydro that:

   i) the back-up facility is adequate to serve the entire SEP load given the type of load and possibly lengthy interruption of SEP supply; and

   ii) the installation and operation of the back-up facility complies with all government regulations including all municipal and provincial zoning and environmental regulations.

d) Certification of back-up as described in Subsections 11 c) i) and ii) must be provided in writing to Manitoba Hydro when the customer first accepts SEP service and by no later than October 1, of every year thereafter that the customer is accepting SEP service.

e) If a customer ceases, or is unable to maintain an adequate back-up facility:

   i) the customer must notify Manitoba Hydro in writing of the situation immediately; and

   ii) should the customer continue to use SEP, Manitoba Hydro may bill the customer for Demand (kVA) associated with SEP energy use at the applicable General Service Large or Medium Demand Charge for the period of time the back-up facility is considered to be, or to have been, inadequate. The appropriate SEP Energy and Distribution Charges will continue to be applied to all energy use; and

   iii) Notice to convert load served under SEP to firm service will be as set out in Section 3.

GENERAL SERVICE ALTERNATIVE RATES
SURPLUS ENERGY PROGRAM RATE

General Service-Medium (Utility-Owned Transformer)	**Tariff No. 50-19:**
Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.62¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large 750 V to Not Exceeding 30 kV	**Tariff No. 50-20:**
Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.33¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large 30 kV to Not Exceeding 100 kV	**Tariff No. 50-21:**
Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.14¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large Exceeding 100 kV	**Tariff No. 50-22:**
Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.06¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

Hours	**Summer (May 1 - October 31)**	**Winter (November 1 - April 30)**
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

SURPLUS ENERGY PROGRAM
PROCEDURE FOR INTERIM EX PARTE
PUBLIC UTILITIES BOARD (PUB) APPROVAL OF SEP RATE

---

1. Each Wednesday by 9:00 AM Central Time (CT), Manitoba Hydro shall:

   i) email to the Board a copy of Schedule SEP-1 which shall include the Energy Charge for the Time-of-Use periods for all General Service Medium and Large classes of service;

   ii) indicate the expected source of SEP energy (i.e. from displaced exports, Manitoba Hydro generation, or imports); and

   iii) warrant that the price has been estimated using approved methodology as set out in Schedule SEP-3.

   The "Delivered Microsoft Outlook" message for the email will serve as confirmation that the PUB has received the schedule.

2. If Schedule SEP-1 is acceptable, the PUB will provide interim *ex parte* approval of the rates and email the Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT the same day. If the proposed Schedule, for any reason, is not acceptable, the PUB will contact Manitoba Hydro as soon as possible and attempt to resolve any concerns. If these concerns cannot be resolved by Wednesday at 3:00 PM CT, Manitoba Hydro will then forthwith contact customers to inform them that SEP energy is not available for the following week.

3. If the PUB emails an Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT on Wednesday, Manitoba Hydro shall fax/email the approved rate schedule to the SEP customers by 3:00 PM CT the same day.

4. Steps 1 through 3 shall be repeated each Wednesday that SEP energy is available.

SURPLUS ENERGY PROGRAM
PROCEDURE FOR DETERMINATION OF
WEEKLY ENERGY CHARGE

The SEP Energy Charge for each of the three Time-of-Use (TOU) periods shall be determined by Manitoba Hydro weekly, on a forecast basis for the following week (Monday through Sunday), as follows:

- If SEP energy displaces extra-provincial sales, the Energy Charge shall be such as to collect the revenue that would have been received from the foregone energy sales from the week to which the Energy Charge applies.

- If SEP energy is provided from purchased power, the Energy Charge shall be the amount necessary to recover the cost of the purchased power, including Transmission Service Charges, Administration Fees and Losses, plus 10% as a contribution to reserves.

- If SEP energy is provided from Manitoba Hydro generation, the Energy Charge shall be the amount necessary to collect the incremental cost of generation including Transmission Losses, plus 10% as a contribution to reserves. The latter is to administer energy and to cover a small share of fixed cost or contribution to reserves.

- In forecasting the weekly energy prices, Manitoba Hydro will consider what price experience has been under similar conditions of seasonality, expected demand and supply in the Midwest Independent Transmission System Operator (MISO) Market. An adder will be applied to each of the three TOU periods to account for market volatility or unforeseen supply costs. The adders will be adjusted as required to ensure a balance is maintained over the long-term between actual energy costs and revenues from SEP energy.

SURPLUS ENERGY PROGRAM
SELF-GENERATION DISPLACEMENT - OPTION 3
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SURPLUS ENERGY PROGRAM
SELF-GENERATION DISPLACEMENT - OPTION 3
TERMS AND CONDITIONS

ELIGIBILITY

1. SEP - Option 3 is available to electric loads which meet the following qualifications:

   a) Demand must be between 200 kW and 50 000 kW; and

   b) The load must be fully backed up by generating equipment which is leased or owned by the customer and is located on the premises of the SEP load; and

   c) The load is intermittent and for industrial use which can be deferred, for several days, if necessary, should maintenance of back-up generation be required during a period of interruption of SEP energy supply.

      Load would not be considered intermittent if the average monthly load factor exceeds 25%; and

   d) The load must be metered separately from the customer's firm load; and

   e) The load is not being served under the Curtailable Rate Program; and

   f) Manitoba Hydro may require a customer to maintain a minimum Power Factor of 90% as a condition of participation.

CONVERSION TO FIRM SERVICE

2. A customer may convert part or all of the load served under SEP to firm service by providing Manitoba Hydro with advance written notice based on the following notice period options, of which, must be determined and designated on Schedule 'A' of the customer's SEP contract prior to participation in SEP. In all cases Manitoba Hydro may reduce the notice period if, in its sole discretion such reduction can be accomplished without adverse impact to the operations or revenues of the corporation.

   a) A 12 month notice period with an option of:

      i) the customer will pay a premium of 1.0¢ per kWh for energy purchased during the summer peak hours; or

      ii) the customer will agree that load converted on 12 months notice shall be subject to curtailment under the provisions of Option "A" or "R" of the Curtailable Rate Program for the first four months following the conversion; or

b) A notice period dependent on when the said notice is provided, as follows:

i) where notice is provided between September 1 up to and including January 31, a 12 month notice period shall apply; or

ii) where notice is provided between February 1 up to and including April 30, a 16 month notice period shall apply. Where the customer provides notice between February 1 and April 30, the customer may elect at the time notice is given, to convert to the notice provisions outlined in Subsection 3 a) ii) above; or

iii) where notice is provided between May 1 up to and including August 31, the notice period shall not expire prior to August 31 of the following year such that notice will be not greater than 16 months or less than 12 months. Where the customer provides notice between May 1 and August 1, the customer may elect, at the time notice is given, to convert to the notice provisions outlined in Subsection 3 a) ii) above.

BILLING

3. Rates to SEP - Option 3 customers will be set as follows. The rates which will be charged are set out in Schedule SEP-1 (attached) and are subject to weekly approval by the PUB as per Schedule SEP-2 (attached).

a) i) a Basic Charge to cover administration and metering costs as follows:

- For loads of 1 000 kV.A or greater $100.00 per month
- For loads of less than 1 000 kV.A $50.00 per month

ii) an Energy Charge per kWh which will be set for three Time-of-Use periods on a weekly basis; that is, one for each of the peak, shoulder, and off-peak periods. The periods are defined below:

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Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

The Weekly Energy Charge will be determined as per Schedule SEP-3 (attached).

iii) a Distribution Charge per kWh intended to collect approximately one-third of the embedded cost of distribution, subtransmission, and regional transmission.

INTERRUPTIONS

4. On notice by fax/email or phone from Manitoba Hydro, a customer will be required to interrupt electricity supply to the SEP load within 36 hours in one or more of the TOU periods as specified in the notice, and may not resume use of SEP in the specified period(s) until notified by Hydro by fax/email or phone that the interruption is ended.

5. Failure to interrupt SEP load during an interruption can result in additional charges based on the actual costs Manitoba Hydro incurs to supply SEP load during an interruption. The maximum additional charge is $150.00 per kW of Demand and $1.00 per kWh of associated energy.

6. A customer will be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra-provincially.

METERING AND ELECTRIC SERVICE FACILITIES

7. Manitoba Hydro will supply the appropriate metering for a SEP customer.

8. The customer shall be responsible for all costs of building or upgrading regional transmission, subtransmission, distribution and/or dedicated services which may be required to serve SEP load.

CONTRACT REQUIREMENTS

9. A customer will be required to enter into a formal agreement with Manitoba Hydro. The agreement will document the above Terms and Conditions as well as any others considered necessary due to the nature of a specific service.

CUSTOMER WAIVER

10. a) A customer will be required to sign a waiver stating that the customer understands that the Terms and Conditions of SEP provide for:

i) SEP energy prices-per-kWh which can be volatile from week-to-week, and can be extremely high during periods of scarcity in interconnected markets; and

ii) interruption in the supply of SEP energy can be initiated by Manitoba Hydro on 36 hours notice to the customer for any reason; and

iii) possible lengthy periods of interruption.

b) The customer has considered the implications of the foregoing and will comply without objection to interruptions made in accordance with the Terms and Conditions of SEP.

c) The customer must provide certification in writing to Manitoba Hydro that:

  i) the back-up facility is adequate to serve the entire SEP load given the type of load and possibly lengthy interruption of SEP supply; and

  ii) the installation and operation of the back-up facility complies with all government regulations including all municipal and provincial zoning and environmental regulations.

d) Certification of back-up as described in Subsections 11 c) i) and ii) must be provided in writing to Manitoba Hydro when the customer first accepts SEP service and by no later than October 1, of every year thereafter that the customer is accepting SEP service.

e) If a customer ceases, or is unable to maintain an adequate back-up facility:

  i) the customer must notify Manitoba Hydro in writing of the situation immediately; and

  ii) should the customer continue to use SEP, Manitoba Hydro may bill the customer for Demand (kVA) associated with SEP energy use at the applicable General Service Large or Medium Demand Charge for the period of time the back-up facility is considered to be, or to have been, inadequate. The appropriate SEP Energy and Distribution Charges will continue to be applied to all energy use; and

  iii) notice to convert load served under SEP to firm service will be as set out in Section 3.

GENERAL SERVICE ALTERNATIVE RATES
SURPLUS ENERGY PROGRAM RATE

General Service-Medium (Utility-Owned Transformer) **Tariff No. 50-19:**

Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.62¢/kWh
PLUS	
Energy Charge:	
Peak Hours	________
Shoulder Hours	________
Off-Peak Hours	________

General Service-Large 750 V to Not Exceeding 30 kV **Tariff No. 50-20:**

Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.33¢/kWh
PLUS	
Energy Charge:	
Peak Hours	________
Shoulder Hours	________
Off-Peak Hours	________

General Service-Large 30 kV to Not Exceeding 100 kV **Tariff No. 50-21:**

Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.14¢/kWh
PLUS	
Energy Charge:	
Peak Hours	________
Shoulder Hours	________
Off-Peak Hours	________

General Service-Large Exceeding 100 kV **Tariff No. 50-22:**

Basic Monthly Charge:	
SEP Load ≤ 1 000 kV.A	$ 50.00
SEP Load > 1 000 kV.A	$100.00
PLUS	
Distribution Charge:	0.06¢/kWh
PLUS	
Energy Charge:	
Peak Hours	________
Shoulder Hours	________
Off-Peak Hours	________

Hours	Summer (May 1 - October 31)	Winter (November 1 - April 30)
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SURPLUS ENERGY PROGRAM
PROCEDURE FOR INTERIM EX PARTE
PUBLIC UTILITIES BOARD (PUB) APPROVAL OF SEP RATE

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1. Each Wednesday by 9:00 AM Central Time (CT), Manitoba Hydro shall:

   i) email to the Board a copy of Schedule SEP-1 which shall include the Energy Charge for the Time-of-Use periods for all General Service Medium and Large classes of service;

   ii) indicate the expected source of SEP energy (i.e. from displaced exports, Manitoba Hydro generation, or imports); and

   iii) warrant that the price has been estimated using approved methodology as set out in Schedule SEP-3.

   The "Delivered Microsoft Outlook" message for the email will serve as confirmation that the PUB has received the schedule.

2. If Schedule SEP-1 is acceptable, the PUB will provide interim *ex parte* approval of the rates and email the Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT the same day. If the proposed Schedule, for any reason, is not acceptable, the PUB will contact Manitoba Hydro as soon as possible and attempt to resolve any concerns. If these concerns cannot be resolved by Wednesday at 3:00 PM CT, Manitoba Hydro will then forthwith contact customers to inform them that SEP energy is not available for the following week.

3. If the PUB emails an Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT on Wednesday, Manitoba Hydro shall fax/email the approved rate schedule to the SEP customers by 3:00 PM CT the same day.

4. Steps 1 through 3 shall be repeated each Wednesday that SEP energy is available.

SURPLUS ENERGY PROGRAM
PROCEDURE FOR DETERMINATION OF
WEEKLY ENERGY CHARGE

The SEP Energy Charge for each of the three Time-of-Use (TOU) periods shall be determined by Manitoba Hydro weekly, on a forecast basis for the following week (Monday through Sunday), as follows:

- If SEP energy displaces extra-provincial sales, the Energy Charge shall be such as to collect the revenue that would have been received from the foregone energy sales from the week to which the Energy Charge applies.

- If SEP energy is provided from purchased power, the Energy Charge shall be the amount necessary to recover the cost of the purchased power, including Transmission Service Charges, Administration Fees and Losses, plus 10% as a contribution to reserves.

- If SEP energy is provided from Manitoba Hydro generation, the Energy Charge shall be the amount necessary to collect the incremental cost of generation including Transmission Losses, plus 10% as a contribution to reserves. The latter is to administer energy and to cover a small share of fixed cost or contribution to reserves.

- In forecasting the weekly energy prices, Manitoba Hydro will consider what price experience has been under similar conditions of seasonality, expected demand and supply in the Midwest Independent Transmission System Operator (MISO) Market. An adder will be applied to each of the three TOU periods to account for market volatility or unforeseen supply costs. The adders will be adjusted as required to ensure a balance is maintained over the long-term between actual energy costs and revenues from SEP energy.

REPORT TO
THE PUBLIC UTILITIES BOARD

SURPLUS ENERGY PROGRAM

NOVEMBER 1, 2013 – OCTOBER 31, 2014

JANUARY 2015

Manitoba Hydro

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REPORT TO PUBLIC UTILITIES BOARD
SURPLUS ENERGY PROGRAM
NOVEMBER 1, 2013 - OCTOBER 31, 2014

BACKGROUND

The Surplus Energy Program ("SEP") was first approved on June 30, 2000 by Public Utilities Board ("PUB") Order No. 90/00. The program is intended to enable customers to purchase surplus energy at market prices that are determined on a weekly basis for peak, shoulder, and off-peak periods. Customers began accepting service under the Terms and Conditions of this temporary program on December 4, 2000. Manitoba Hydro filed an Application on April 5, 2012 requesting minor modifications to SEP Option 1, as well as to make SEP a permanent rate offering. These proposals were subsequently included in Manitoba Hydro's 2012/13 and 2013/14 General Rate Application ("GRA"). At the conclusion of the GRA hearing, the PUB issued Board Order 43/13 dated April 26, 2013 which approved SEP Option 1 on an interim basis, and approved Options 2 and 3 as a permanent rate offering. Manitoba Hydro is seeking final approval of the changes to SEP Option 1 Terms and Conditions in its 2015/16 and 2016/17 GRA.

As part of the original Board Order which approved SEP, Manitoba Hydro was directed to file annual reports on the status of the program. This is the 14th report which covers the period November 1, 2013 to October 31, 2014. For a brief history of PUB Orders and Manitoba Hydro's applications and reports with respect to the SEP Program, please see Attachment 1.

SUMMARY OF FINDINGS

The SEP Program is a revenue neutral program that offers customers choice and access to surplus energy at prices that reflect Manitoba Hydro's short term marginal cost of energy. To obtain the full benefits of the program customers need to have sufficient flexibility in their operation to take advantage of lower price periods. While the SEP Program is not intended as a rate discount program, market and Manitoba Hydro supply conditions during the past year were such that all SEP customers experienced reduced bills relative to the respective General Service firm rate they would have otherwise billed under.

The cost to Manitoba Hydro for providing surplus energy to SEP customers during the current one-year reporting period was $1,068,652. Total revenue collected under SEP was $1,055,103 excluding Basic Charges and Distribution Charges, resulting in a net revenue loss to Manitoba Hydro of $13,549.

The main factors that affected SEP prices during the current reporting year were extra-provincial market prices, weather driven electrical load-water conditions, and transmission constraints to neighboring markets. Water conditions during this period were above average. Hydraulic generation through the winter and early spring was above average because there was significant storage carry forward from the previous year. However, persistent below average temperatures in the region resulted in increased domestic electrical demand and added pressure to market prices during the winter months. Colder than normal weather resulted in increased short-term marginal energy costs, particularly from mid-January to mid-February. Inflows were well above average through spring and summer across all basins, and were record high in the Winnipeg River basin, allowing for above average hydraulic generation through the entire reporting period. Spill conditions occurred through the late spring, summer and fall due to high inflows. An extended transmission outage through October 2014 restricted Manitoba Hydro exports and added downward pressure on the SEP rates during this period. Energy is sourced from avoided spill, defined as the water that would have been spilled absent of the SEP during times when tie-lines to neighboring markets are fully utilized and there is unused hydro generation capacity. These factors, combined with a growth in wind generation in the US market, as well as continued low natural gas costs have kept SEP prices generally lower compared to the prices experienced in 2007/08.

The majority (70%) of the Peak SEP energy supply was sourced from displaced exports, while 30% was sourced through avoided spill. For the Shoulder period, 57% was sourced through exports, and 43% through avoided spill. For the Off-Peak period, 51% of energy was sourced through exports, 46% through avoided spill, and 3% was sourced through imports.

Average 2013/14 SEP prices were the 5th lowest of the 14 years the program has been available and were similar to the 2009/10 average prices. Higher average SEP prices were seen from 2000 to 2009. SEP General Service Medium average prices were: On-Peak 4.318 ¢/kWh ranging from 0.426 ¢/kWh to 7.447 ¢/kWh; Shoulder 3.223 ¢/kWh ranging from 0.426 ¢/kWh to 6.299 ¢/kWh; and Off-Peak 1.832 ¢/kWh ranging from 0.426 ¢/kWh to 4.157 ¢/kWh.

There was no interruption in service during the 12 month reporting period.

DESCRIPTION OF PROGRAM

Eligibility:

The Program makes surplus energy available on an interruptible basis to Manitoba Hydro General Service customers. Eligible customers can participate in one of the following three options:

1) Industrial Load - Option 1 - available to industrial loads whose Total Demand is 1,000 kVA or greater. Total Demand is defined as the Reference Level of Demand plus the level of demand associated with SEP. Under this option customers may only designate 25%[1] of their total load as SEP load, with the remaining 75% being their Reference Demand. Manitoba Hydro is proposing changes to the Reference Demand to allow customers to have a different Reference Demand for each of the three pricing periods. The highest designated Reference Demand would be used in determining the customer's monthly billed demand.

2) Heating Load - Option 2 – available to electrical loads of 200 kW or greater. The electricity is to be used for space and/or water heating only and must be separately metered from the customer's firm load. Customers must have an alternate back-up energy source capable of heating the entire load in the event of an interruption.

3) Self-Generation Displacement - Option 3 – available to industrial intermittent loads with total demand between 200 kW to 50,000 kW. Load would not be considered intermittent if the average monthly load factor exceeds 25%. The load must be separately metered from the customer's firm load and must be fully backed up by generating equipment which is leased or owned by the customer and is located on the premises of the SEP load.

Billing:

All SEP customers are billed a monthly Basic Charge, Distribution Charge and an Energy Charge. The Basic Charge is $50.00 per month for customers with connected loads of 1,000 kVA or less, and $100.00 per month for connected loads greater than 1,000 kVA. The Distribution Charge per kilowatt-hour ranges from 0.06¢ to 0.62¢ dependent on customer class. The Energy Charge per kilowatt-hour, applicable to three pricing periods, varies based on

[1] Customers can designate up to 50% of their load as SEP provided they have an alternate back-up source of energy to supply the amount in excess of the 25%.

expected market prices from week-to-week. The three pricing periods are peak, shoulder and off-peak, and are further defined by season as shown in the following table:

	Summer (May 1 – October 31)	**Winter (November 1 – April 30)**
Peak	12:01 to 20:00 hours Monday to Friday Except Statutory Holidays	07:01 to 11:00 hours and 16:01 to 20:00 hours Monday to Friday Except Statutory Holidays
Shoulder	All hours except Peak, every day from 07:01 to 23:00	
Off-Peak	All night time hours from 23:01 to 07:00 hours	

PROGRAM SUBSCRIPTION

There were 28 customers on the SEP program for this reporting period. Of the 28 customers, 25 are Option 2 (Heating Load) and 3 are Option 3 (Self-Generation Displacement). There are no Option 1 (Industrial Load) customers.

All the Option 2 customers are classed as General Service Medium Demand and fall under the following industry types:

Agricultural and Related Service Industries	7 customers
Educational Service Industries	12 customers
Local Government Service Industries	4 customers
Machinery & Equipment	1 customer
Retail Food, Beverage and Drug Industries	1 customer

All the Option 3 customers are in the General Service Large Demand 750 V – 30 kV class under the following industry types:

Quarry & Sand Pit Industries	2 customers
Paper & Allied Products Industries	1 customers

All customers have signed a waiver ensuring they have appropriate back-up facilities to support their loads in the event of an interruption.

POTENTIAL CUSTOMERS

One customer in the welding industry is currently in the process of contracting for SEP. Customers in the agricultural industry who currently use coal are assessing alternate fuel choices and may consider SEP in the future due to the Manitoba government's ban on the use of coal for space and water heating in 2017.

CUSTOMER EXPERIENCE

Manitoba Hydro is not aware of any customer complaints regarding the SEP Program.

There have been no difficulties encountered with communication of pricing information to customers on a timely basis. This information is faxed or emailed to customers on Wednesday of each week, providing prices that will be in place for the following week beginning Sunday at midnight.

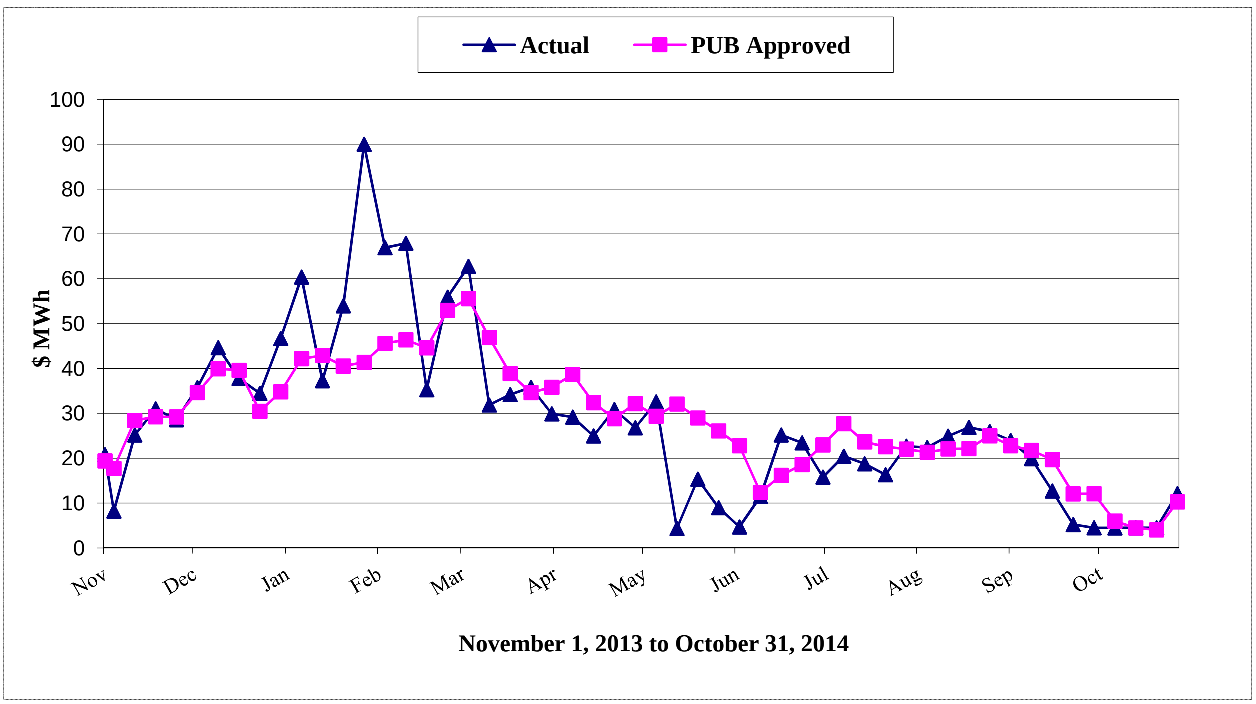
SEP ENERGY PRICES

Each Wednesday Manitoba Hydro applies to the Public Utilities Board for interim *ex parte* approval of the SEP Energy Rates to be in effect the following Monday through Sunday. The following table compares the weekly average prices approved by the PUB with the actual average after-the-fact prices throughout the reporting period. Attachment 2 provides the weekly rates for each pricing period for both Medium and Large 750 V - 30 kV classes. The information is also shown graphically on page 7.

SEP - Average Weekly Rate Per MWh				
Week Beginning	**Actual**	**PUB Approved**	**Difference**	**PUB Order No.**
November 1, 2013	$20.79	$19.39	$1.40	131/13
November 4, 2013	$8.21	$17.71	($9.50)	133/13
November 11, 2013	$25.17	$28.43	($3.26)	135/13
November 18, 2013	$31.01	$29.25	$1.76	137/13
November 25, 2013	$28.55	$29.21	($0.66)	138/13
December 2, 2013	$35.71	$34.62	$1.09	141/13
December 9, 2013	$44.65	$39.96	$4.69	146/13
December 16, 2013	$37.76	$39.60	($1.84)	152/13
December 23, 2013	$34.45	$30.46	$3.99	155/13

SEP - Average Weekly Rate Per MWh				
Week Beginning	**Actual**	**PUB Approved**	**Difference**	**PUB Order No.**
December 30, 2013	$46.69	$34.81	$11.88	156/13
January 6, 2014	$60.38	$42.19	$18.19	157/13
January 13, 2014	$37.27	$42.91	($5.64)	1/14
January 20, 2014	$53.97	$40.55	$13.42	5/14
January 27, 2014	$89.98	$41.39	$48.59	10/14
February 3, 2014	$66.93	$45.60	$21.33	11/14
February 10, 2014	$67.91	$46.39	$21.52	14/14
February 17, 2014	$35.28	$44.62	($9.34)	18/14
February 24, 2014	$55.91	$52.98	$2.93	20/14
March 3, 2014	$62.78	$55.58	$7.20	21/14
March 10, 2014	$31.87	$46.89	($15.02)	24/14
March 17, 2014	$34.20	$38.88	($4.68)	28/14
March 24, 2014	$35.81	$34.63	$1.18	33/14
March 31, 2014	$29.90	$35.83	($5.93)	40/14
April 7, 2014	$29.17	$38.65	($9.48)	36/14
April 14, 2014	$24.97	$32.38	($7.41)	38/14
April 21, 2014	$30.86	$28.83	$2.03	41/14
April 28, 2014	$26.79	$32.17	($5.38)	44/14
May 5, 2014	$32.55	$29.37	$3.18	47/14
May 12, 2014	$4.34	$32.08	($27.74)	50/14
May 19, 2014	$15.34	$28.98	($13.64)	53/14
May 26, 2014	$8.97	$26.09	($17.12)	55/14
June 2, 2014	$4.68	$22.77	($18.09)	58/14
June 9, 2014	$11.48	$12.36	($0.88)	60/14
June 16, 2014	$25.18	$16.18	$9.00	65/14
June 23, 2014	$23.43	$18.57	$4.86	67/14
June 30, 2014	$15.79	$22.98	($7.19)	71/14
July 7, 2014	$20.45	$27.70	($7.25)	74/14
July 14, 2014	$18.75	$23.64	($4.89)	77/14
July 21, 2014	$16.32	$22.56	($6.24)	80/14
July 28, 2014	$22.68	$22.03	$0.65	84/14
August 4, 2014	$22.38	$21.32	$1.06	88/14
August 11, 2014	$24.93	$22.08	$2.85	89/14
August 18, 2014	$26.87	$22.15	$4.72	92/14
August 25, 2014	$25.94	$25.01	$0.93	94/14
September 1, 2014	$23.95	$22.80	$1.15	97/14

SEP - Average Weekly Rate Per MWh				
Week Beginning	**Actual**	**PUB Approved**	**Difference**	**PUB Order No.**
September 8, 2014	$19.88	$21.75	($1.87)	99/14
September 15, 2014	$12.70	$19.70	($7.00)	101/14
September 22, 2014	$5.21	$12.06	($6.85)	105/14
September 29, 2014	$4.48	$12.07	($7.59)	111/14
October 6, 2014	$4.47	$5.98	($1.51)	113/14
October 13, 2014	$4.50	$4.46	$0.04	114/14
October 20, 2014	$4.49	$4.04	$0.45	116/14
October 27, 2014	$12.11	$10.27	$1.84	117/14
Average	**$28.28**	**$28.55**	**($0.27)**	



SOURCE OF SUPPLY FOR SEP ENERGY

As part of its weekly Application to the PUB, Manitoba Hydro is required to indicate the expected source of supply for SEP energy that is used to derive the marginal cost of energy for the weekly SEP energy rates. The following summary table compares the expected source of supply, which was the basis of the weekly Applications, to the actual source of supply as determined after-the-fact. A more detailed analysis by week is provided in Attachment 3.

SEP Energy Supply Source (%)														
November 1, 2013 to October 31, 2014														
	Actual							Forecast						
	Imports			Exports			Avoided Spill	Imports			Exports			Avoided Spill
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	
Peak	0%	0%	0%	70%	0%	0%	30%	1%	0%	0%	78%	0%	0%	21%
Shoulder	0%	0%	0%	0%	57%	0%	43%	0%	0%	0%	0%	59%	0%	41%
Off-Peak	0%	0%	3%	0%	0%	51%	46%	0%	0%	0%	0%	0%	54%	46%

Water conditions during this reporting period were above average. Hydraulic generation through the winter and early spring was above average because there was significant storage carry forward from the previous year. Inflows were well above average through spring and summer across all basins, and were record high in the Winnipeg River basin, allowing for above average hydraulic generation through the entire reporting period. Spill conditions occurred through the late spring, summer and fall due to high inflows and outages at Manitoba Hydro's interconnection to the United States.

Through-out the reporting period SEP energy was sourced mostly from displaced exports: 70% Peak, 57% Shoulder, and 51% Off-Peak. In January, February and March, 3% of the Off-Peak energy was sourced from imports. Starting in May, the remainder of the energy supply was sourced from avoided spill: 30% Peak, 43% Shoulder, and 46% Off-Peak. Avoided spill occurs during periods when tie-lines to neighboring markets are fully utilized and firm load has been met, combined with unused hydro generation capacity. In general, avoided spill is more frequently experienced during Off-Peak periods due to low over-night Manitoba loads.

ACTUAL SALES

Total energy and revenue of SEP sales over the period November 1, 2013 to October 31, 2014 were 29,371 MWh and $1,230,282 (excluding $19,200 in Basic Charges). The distribution of the energy and revenue by pricing period is shown below. A more detailed analysis by week is provided in Attachments 4, 5 and 6.

Period	SEP Energy Sales MWh	Revenue		
		Distribution Charge	Energy Charge	Total
Peak	6,865	$40,093	$328,178	$368,271
Shoulder	12,812	$76,395	$482,912	$559,307
Off Peak	9,694	$58,692	$244,013	$302,705
Total	**29,371**	**$175,180**	**$1,055,103**	**$1,230,282**

Over the period November 1, 2013 through to October 31, 2014, the value of SEP energy (using after-the-fact prices) was $1,068,652. Revenue from energy sales was $1,055,103 resulting in net revenue loss to Manitoba Hydro of $13,549 for the year. The following table summarizes Manitoba Hydro net revenue for each time-of-use period. A more detailed analysis by week is found in Attachment 7.

SEP Energy Revenues versus Costs				
Period	SEP Energy Sales MWh	SEP Sales*	Value of SEP Energy to Manitoba Hydro	Manitoba Hydro Net Revenue
Peak	6,865	$328,178	$347,343	($19,165)
Shoulder	12,812	$482,912	$451,570	$31,341
Off Peak	9,694	$244,013	$269,738	($25,725)
Total	**29,371**	**$1,055,103**	**$1,068,652**	**($13,549)**

* SEP Sales do not include $175,180 from Distribution Charges or $19,200 from Basic Charges. The value of SEP energy to Manitoba Hydro is calculated by multiplying weekly MWh sales by the actual weekly SEP energy rate at common bus.

YEAR-TO-DATE RESULTS

The following is a summary of the program since its inception on December 4, 2000.

Program Year	Number of Services		
	General Service Medium	GS Large (750 V to 30 kV)	Total
Dec 4, 2000 to Oct 31, 2001	24	4	28
Nov 1, 2001 to Oct 31, 2002	27	6	33
Nov 1, 2002 to Oct 31, 2003	27	6	33
Nov 1, 2003 to Oct 31, 2004	25	6	31
Nov 1, 2004 to Oct 31, 2005	22	6	28
Nov 1, 2005 to Oct 31, 2006	22	6	28
Nov 1, 2006 to Oct 31, 2007	22	5	27
Nov 1, 2007 to Oct 31, 2008	20	5	25
Nov 1, 2008 to Oct 31, 2009	19	5	24
Nov 1, 2009 to Oct 31, 2010	19	5	24
Nov 1, 2010 to Oct 31, 2011	21	5	26
Nov 1, 2011 to Oct 31, 2012	24	5	29
Nov 1, 2012 to Oct 31, 2013	25	3	28
Nov 1, 2013 to Oct 31, 2014	25	3	28

Program Year	SEP Actual Sales			
	Basic Charge	Distribution Charge	Energy Charge	Total Revenue
Dec 4, 2000 to Oct 31, 2001	$15,436	$105,948	$880,033	$1,001,418
Nov 1, 2001 to Oct 31, 2002	$20,169	$164,565	$959,529	$1,144,263
Nov 1, 2002 to Oct 31, 2003	$21,330	$111,347	$1,061,522	$1,194,200
Nov 1, 2003 to Oct 31, 2004	$21,700	$112,572	$1,201,434	$1,335,707
Nov 1, 2004 to Oct 31, 2005	$20,180	$147,530	$1,277,816	$1,445,526
Nov 1, 2005 to Oct 31, 2006	$19,200	$134,445	$1,248,314	$1,401,959
Nov 1, 2006 to Oct 31, 2007	$19,178	$128,724	$1,414,933	$1,562,835
Nov 1, 2007 to Oct 31, 2008	$17,150	$131,068	$1,149,472	$1,297,689
Nov 1, 2008 to Oct 31, 2009	$16,790	$139,021	$932,076	$1,087,887
Nov 1, 2009 to Oct 31, 2010	$16,800	$115,817	$594,374	$726,991
Nov 1, 2010 to Oct 31, 2011	$17,650	$152,400	$672,493	$842,543
Nov 1, 2011 to Oct 31, 2012	$18,927	$154,379	$614,629	$787,935
Nov 1, 2012 to Oct 31, 2013	$19,450	$172,097	$793,148	$984,695
Nov 1, 2013 to Oct 31, 2014	$19,200	$175,180	$1,055,103	$1,249,482
Total	**$263,160**	**$1,945,094**	**$13,854,875**	**$16,063,129**

Program Year	SEP Energy Sales vs. Costs			
	SEP Sales		Marginal Cost to MH	Net Revenue to MH
	MWh	Energy Charge		
Dec 4, 2000 to Oct 31, 2001	18,123	$880,033	$891,308	($11,275)
Nov 1, 2001 to Oct 31, 2002	28,808	$959,529	$994,233	($34,704)
Nov 1, 2002 to Oct 31, 2003	19,473	$1,061,522	$1,056,307	$5,215
Nov 1, 2003 to Oct 31, 2004	19,328	$1,201,434	$992,650	$208,784
Nov 1, 2004 to Oct 31, 2005	25,013	$1,277,816	$1,241,792	$36,024
Nov 1, 2005 to Oct 31, 2006	22,927	$1,248,314	$1,161,379	$86,935
Nov 1, 2006 to Oct 31, 2007	22,152	$1,414,933	$1,392,736	$22,197
Nov 1, 2007 to Oct 31, 2008	22,347	$1,149,472	$1,138,131	$11,340
Nov 1, 2008 to Oct 31, 2009	23,393	$932,076	$842,510	$89,565
Nov 1, 2009 to Oct 31, 2010	19,506	$594,374	$577,384	$16,989
Nov 1, 2010 to Oct 31, 2011	25,568	$672,493	$602,184	$70,309
Nov 1, 2011 to Oct 31, 2012	25,763	$614,629	$560,145	$54,484
Nov 1, 2012 to Oct 31, 2013	28,757	$793,148	$772,778	$20,369
Nov 1, 2013 to Oct 31, 2014	29,371	$1,055,103	$1,068,652	($13,549)
Total	**330,528**	**$13,854,875**	**$13,292,189**	**$562,685**

Attachment 1 - SEP: Chronology of PUB Directives, MH Applications, and Reports

PUB Order	Date	PUB Board Findings & MH Applications and Reports Filings
	Oct 25/99	MH files application for approval of the Surplus Energy Program
90/00	Jun 30/00	PUB approves SEP application to March 31, 2004 and directs MH to file annual reports on SEP by no later than January 31 of each year.
	Jul 20/00	MH letter - in response to Board Order 90/00 MH requests variance of 12 month notice provision to range from 12 to 16 months notice.
132/00	Sep 29/00	The PUB varies BO 90/00 such that an SEP customer who chooses to convert to firm service has various notice period options.
	Oct 26/00	MH files revised Terms & Condition of SEP to be in accordance with Board Order 90/00 and 132/00. MH also advises its intent to waive requirement for a Professional Engineer Certification of back-up facilities
143/01	Sep 13/01	The PUB approves the revised Terms and Conditions as noted in MH's letter of Oct 26/00.
	Sep 21/01	MH files revised SEP Terms and Conditions as required by BO 143/01
	Nov 30/01	MH files Report #1 on SEP for period Dec 4/00 to Oct 31/01
	Mar 12/03	MH files Report #2 on SEP for period Nov 1/01 to Oct 31/02
	Mar 24/03	MH - by correspondence requests SEP be extended to Mar 31/05 on ex parte bases.
153/03	Oct 31/03	PUB approves request for extension of SEP to March 31, 2005 on an interim ex parte basis.
	Jan 29/04	As part of 2004 GRA (Appendix 9.2.2, Volume 3) MH requests SEP program be extended two more years to March 31, 2007. MH files Report #3 on SEP for period Nov 1/02 to Oct 31/03
101/04	Jul 28/04	PUB approves MH's application to extend Terms and Conditions of the SEP, as proposed and amended by MH, until March 31, 2007.
	May 17/05	MH files Report #4 on SEP for period Nov 1/03 to Oct 31/04
	Jan 23/06	MH files Report #5 on SEP for period Nov 1/04 to Oct 31/05
	Apr 20/06	MH applies to extend SEP Terms & Conditions to Mar 31/09
	Sep 7/06	PUB issues letter advising they are prepared to extend SEP to Oct 31/07. Also state their intention to review SEP in upcoming MH GRA.
	Sep 28/06	MH letter requests PUB reconsider their position and extend program, at minimum to October 31, 2008, noting customers need to plan for modifications or elimination of SEP and require minimum 12 months notice period.
173/06	Dec 21/06	PUB approves extension of SEP to the earlier of October 31, 2007 or an application to amend by MH. Advises MH to include a review of SEP in its GRA filing, due no later than August 1, 2007.

PUB Order	Date	PUB Board Findings & MH Applications and Reports Filings
	Jan 12/07	MH files Report #6 on SEP for period Nov 1/05 to Oct 31/06
	Aug 1/07	GRA filing - MH requests immediate approval to extend SEP to October 31/08 with final approval to extend the program to March 31/13 as it is expected hearing will not take place until early 2008.
136/07	Oct 26/07	PUB approves extension of SEP to April 30, 2009 on an interim basis, unless amended or extended by a further Order of the Board.
	Feb 5/08	MH files Report #7 on SEP for period Nov 1/06 to Oct 31/07
90/08	Jun 30/08	PUB approves extension of SEP until October 31, 2008, with the application for a further extension to March 31, 2013 to be dealt with in the subsequent Order.
116/08	Jul 29/08	PUB approves extension of the SEP to October 31, 2008; on condition annual reports continue to be provided. Also raises concern with MH's marketing practices that yield extremely low prices for off-peak exports. MH directed to file a report by January 15, 2009 evaluating SEP, including monthly historical data from 2000 to 2008.
	Sep 18/08	MH files application to vary BO 116/08, requesting PUB extend the date for filing of SEP report to February 28, 2009.
150/08	Nov 7/08	PUB agrees to vary deadline date for the SEP report to February 28, 2009 and approves extension of SEP to April 30, 2009. PUB indicates final approval of SEP to March 31, 2013 will follow once receipt and review of the February 28, 2009 SEP Annual Report is complete.
	Mar 4/09	MH files Report #8 on SEP for period Nov 1/07 to Oct 31/08
57/09	Apr 28/09	PUB approves SEP to March 31, 2013
	Mar 11/10	MH files Report #9 on SEP for period Nov 1/08 to Oct 31/09
	May 11/11	MH files Report #10 on SEP for period Nov 1/09 to Oct 31/10
	April 5/12	MH files an application to vary the Terms and Conditions as well as Report #11 on SEP for period Nov 1/10 to Oct 31/11
111/12	Aug 22/12	PUB approved extension of the SEP to March 31, 2014 to allow time for review of the MH's SEP application during MH's 2012/13 and 2013/14 GRA.
	Mar 11/13	MH files Report #12 on SEP for period Nov 1/11 to Oct 31/12
43/13	Apr 26/13	PUB approves Option 1 Terms and Conditions on an interim basis, to be reviewed at a Cost of Service/Time of Use hearing. PUB approves Option 2 and 3 as a permanent rate offering.
	Jan 31/14	MH files Report #13 on SEP for period Nov 1/12 to Oct 31/13

Attachment 2 - PUB Approved Weekly SEP Rates

PUB APPROVED WEEKLY SEP RATES ¢ / kWh						
Week Beginning	General Service Medium			General Service Large 750 V to 30 kV		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
November 1, 2013	3.295	2.065	1.123	3.251	2.038	1.108
November 4, 2013	2.605	2.230	0.870	2.571	2.201	0.859
November 11, 2013	4.229	3.068	2.191	4.173	3.027	2.162
November 18, 2013	4.171	3.170	2.195	4.116	3.128	2.165
November 25, 2013	4.457	2.952	2.258	4.398	2.913	2.228
December 2, 2013	4.664	3.834	2.685	4.603	3.783	2.650
December 9, 2013	5.956	4.076	3.140	5.877	4.021	3.098
December 16, 2013	5.273	4.607	2.832	5.203	4.546	2.794
December 23, 2013	4.715	3.472	2.154	4.653	3.426	2.125
December 30, 2013	5.018	3.833	2.663	4.951	3.782	2.628
January 6, 2014	5.094	4.601	3.786	5.026	4.540	3.735
January 13, 2014	5.631	4.816	3.355	5.556	4.752	3.310
January 20, 2014	5.497	4.334	3.323	5.424	4.277	3.279
January 27, 2014	5.540	4.388	3.488	5.467	4.330	3.442
February 3, 2014	5.893	5.251	3.458	5.814	5.181	3.412
February 10, 2014	6.035	5.343	3.489	5.955	5.272	3.442
February 17, 2014	5.926	4.997	3.584	5.848	4.930	3.536
February 24, 2014	7.384	5.789	4.035	7.286	5.712	3.981
March 3, 2014	7.447	6.299	4.157	7.348	6.215	4.102
March 10, 2014	6.693	4.812	3.858	6.604	4.749	3.806
March 17, 2014	5.702	4.284	2.712	5.626	4.227	2.676
March 24, 2014	4.737	3.850	2.616	4.674	3.799	2.581
March 31, 2014	4.741	3.969	2.840	4.678	3.916	2.802
April 7, 2014	5.288	4.436	2.741	5.218	4.377	2.705
April 14, 2014	4.670	3.722	2.254	4.608	3.673	2.224
April 21, 2014	3.769	3.538	1.908	3.719	3.491	1.882
April 28, 2014	4.628	3.738	2.060	4.566	3.689	2.033
May 5, 2014	4.533	3.380	1.703	4.472	3.336	1.681
May 12, 2014	4.175	3.962	2.069	4.119	3.909	2.042
May 19, 2014	4.420	3.681	1.379	4.361	3.632	1.361
May 26, 2014	5.182	3.128	0.529	5.113	3.086	0.522
June 2, 2014	4.226	2.842	0.527	4.170	2.804	0.520

PUB APPROVED WEEKLY SEP RATES ¢ / kWh						
Week Beginning	**General Service Medium**			**General Service Large 750 V to 30 kV**		
	Peak	**Shoulder**	**Off-Peak**	**Peak**	**Shoulder**	**Off-Peak**
June 9, 2014	3.097	0.910	0.528	3.056	0.897	0.521
June 16, 2014	3.450	1.681	0.490	3.404	1.658	0.483
June 23, 2014	4.293	1.801	0.491	4.236	1.777	0.484
June 30, 2014	4.634	2.756	0.682	4.573	2.719	0.672
July 7, 2014	5.615	3.003	0.886	5.540	2.963	0.874
July 14, 2014	4.240	2.851	0.783	4.184	2.813	0.772
July 21, 2014	4.189	2.657	0.726	4.134	2.621	0.717
July 28, 2014	3.668	2.816	0.725	3.620	2.779	0.715
August 4, 2014	4.330	2.551	0.623	4.273	2.517	0.615
August 11, 2014	4.099	2.679	0.609	4.044	2.644	0.601
August 18, 2014	4.113	2.688	0.611	4.059	2.652	0.603
August 25, 2014	4.170	2.902	1.198	4.115	2.863	1.182
September 1, 2014	3.855	2.665	1.200	3.804	2.630	1.184
September 8, 2014	3.311	2.582	1.192	3.267	2.548	1.176
September 15, 2014	2.960	2.369	1.068	2.920	2.338	1.054
September 22, 2014	2.259	1.242	0.602	2.229	1.226	0.594
September 29, 2014	2.262	1.244	0.603	2.232	1.227	0.595
October 6, 2014	0.852	0.617	0.489	0.840	0.609	0.482
October 13, 2014	0.470	0.470	0.470	0.464	0.464	0.464
October 20, 2014	0.426	0.426	0.426	0.421	0.421	0.421
October 27, 2014	0.951	1.458	0.693	0.938	1.438	0.683
Average Rate	**4.318**	**3.223**	**1.832**	**4.260**	**3.180**	**1.807**
Maximum Rate	**7.447**	**6.299**	**4.157**	**7.348**	**6.215**	**4.102**
Minimum Rate	**0.426**	**0.426**	**0.426**	**0.421**	**0.421**	**0.421**
Class Rev/kWh	**4.931**	**3.864**	**2.550**	**3.720**	**2.706**	**1.904**

Attachment 3 - SEP Energy Supply Source

SEP Energy Supply Source (%) November 1, 2013 to October 31, 2014															
Week Of		Actual							Forecast						
		Imports			Exports			Avoided Spill	Imports			Exports			Avoided Spill
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	
Nov 01/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	20	0	80
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	33	67
Nov 04/13	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Nov 11/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Nov 18/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Nov 25/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Dec 02/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Dec 09/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Dec 16/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Dec 23/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Dec 30/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0

SEP Energy Supply Source (%)
November 1, 2013 to October 31, 2014

Week Of		Actual							Forecast						
		Imports			Exports			Avoided Spill	Imports			Exports			Avoided Spill
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	
Jan 06/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	29	0	0	71	0	0	0	0	0	0	100	0
Jan 13/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	14	0	0	86	0	0	0	0	0	0	100	0
Jan 20/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	14	0	0	86	0	0	0	14	0	0	86	0
Jan 27/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Feb 03/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Feb 10/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Feb 17/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Feb 24/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	43	0	0	57	0	0	0	0	0	0	100	0
Mar 03/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0
Mar 10/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	14	0	0	86	0	0	0	0	0	0	100	0
Mar 17/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0

SEP Energy Supply Source (%) November 1, 2013 to October 31, 2014																
		Actual							Forecast							
		Imports			Exports				Imports			Exports				
Week Of		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Avoided Spill	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Avoided Spill	
Mar 2413	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	14	0	0	86	0	0	0	0	0	0	100	0	
Mar 31/13	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	14	0	0	86	0	0	0	0	0	0	100	0	
Apr 07/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0	
Apr 14/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0	
Apr 21/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0	
Apr 28/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0	
May 05/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	100	0	0	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	100	0	0	0	0	0	0	100	0	
May 12/14	Peak	0	0	0	20	0	0	80	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	11	0	89	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	14	86	0	0	0	0	0	100	0	
May 19/14	Peak	0	0	0	50	0	0	50	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	20	0	80	0	0	0	0	100	0	0	
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	100	0	
May 26/14	Peak	0	0	0	20	0	0	80	0	0	0	100	0	0	0	
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	56	0	44	
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100	

SEP Energy Supply Source (%) November 1, 2013 to October 31, 2014															
		Actual							Forecast						
		Imports			Exports				Imports			Exports			
Week Of		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Avoided Spill	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Avoided Spill
Jun 02/14	Peak	0	0	0	0	0	0	100	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	56	0	44
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jun 09/14	Peak	0	0	0	20	0	0	80	0	0	0	20	0	0	80
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	11	0	89
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jun 16/14	Peak	0	0	0	20	0	0	80	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	44	0	56	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jun 23/14	Peak	50	0	0	60	0	0	40	0	0	0	80	0	0	20
	Shoulder	0	0	0	0	22	0	78	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jun 30/14	Peak	0	0	0	75	0	0	25	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	20	0	80
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jul 07/14	Peak	0	0	0	40	0	0	60	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	11	0	89	0	0	0	0	56	0	44
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jul 14/14	Peak	0	0	0	40	0	0	60	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	22	0	78	0	0	0	0	11	0	89
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jul 21/14	Peak	0	0	0	40	0	0	60	0	0	0	60	0	0	40
	Shoulder	0	0	0	0	11	0	89	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Jul 28/14	Peak	0	0	0	80	0	0	20	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	33	0	67	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Aug 04/14	Peak	0	0	0	100	0	0	0	75	0	0	0	0	0	25
	Shoulder	0	0	0	0	10	0	90	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Aug 11/14	Peak	0	0	0	80	0	0	20	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	22	0	78	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100

SEP Energy Supply Source (%)
November 1, 2013 to October 31, 2014

Week Of		Actual							Forecast						
		Imports			Exports			Avoided Spill	Imports			Exports			Avoided Spill
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	
Aug 18/14	Peak	0	0	0	60	0	0	40	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	22	0	78	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	57	43	0	0	0	0	0	0	100
Aug 25/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	11	0	89	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	14	86	0	0	0	0	0	0	100
Sep 01/14	Peak	0	0	0	100	0	0	0	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	50	0	50	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	57	43	0	0	0	0	0	0	100
Sep 08/14	Peak	0	0	0	80	0	0	20	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	22	0	78	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	29	71	0	0	0	0	0	0	100
Sep 15/14	Peak	0	0	0	60	0	0	40	0	0	0	100	0	0	0
	Shoulder	0	0	0	0	11	0	89	0	0	0	0	22	0	78
	Off-Peak	0	0	0	0	0	14	86	0	0	0	0	0	29	71
Sep 22/14	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Sep 29/14	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Oct 06/14	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Oct 13/14	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Oct 20/14	Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Shoulder	0	0	0	0	0	0	100	0	0	0	0	0	0	100
	Off-Peak	0	0	0	0	0	0	100	0	0	0	0	0	0	100
Oct 27/14	Peak	0	0	0	20	0	0	80	0	0	0	20	0	0	80
	Shoulder	0	0	0	0	20	0	80	0	0	0	0	20	0	80
	Off-Peak	0	0	0	0	0	20	80	0	0	0	0	0	0	100
Overall Avg		0	0	1	24	19	17	40	1	0	0	26	19	18	36

Attachment 4 - Total Energy Sales in MWh

SURPLUS ENERGY PROGRAM
TOTAL ENERGY SALES IN MWH

Week Beginning	Peak	Shoulder	Off-Peak	Total
November 1, 2013	32	147	97	277
November 4, 2013	173	318	232	724
November 11, 2013	145	373	262	780
November 18, 2013	214	377	296	888
November 25, 2013	228	393	300	921
December 2, 2013	228	423	317	968
December 9, 2013	265	464	363	1,093
December 16, 2013	245	446	346	1,037
December 23, 2013	142	530	336	1,008
December 30, 2013	210	514	359	1,083
January 6, 2014	241	393	323	957
January 13, 2014	226	403	322	951
January 20, 2014	238	428	336	1,002
January 27, 2014	251	419	339	1,009
February 3, 2014	232	418	327	977
February 10, 2014	241	405	333	979
February 17, 2014	166	419	301	886
February 24, 2014	244	430	340	1,014
March 3, 2014	208	340	288	837
March 10, 2014	190	346	277	812
March 17, 2014	179	338	269	786
March 24, 2014	198	338	283	820
March 31, 2014	188	307	265	760
April 7, 2014	147	288	238	672
April 14, 2014	148	315	251	714
April 21, 2014	106	258	200	564
April 28, 2014	124	224	182	530
May 5, 2014	112	205	160	478
May 12, 2014	110	196	159	466
May 19, 2014	69	156	107	331
May 26, 2014	78	125	87	289
June 2, 2014	66	110	74	250

SURPLUS ENERGY PROGRAM
TOTAL ENERGY SALES IN MWH

Week Beginning	Peak	Shoulder	Off-Peak	Total
June 9, 2014	58	84	60	203
June 16, 2014	47	66	40	153
June 23, 2014	39	55	29	124
June 30, 2014	30	65	35	130
July 7, 2014	47	71	40	158
July 14, 2014	43	55	31	129
July 21, 2014	41	58	34	134
July 28, 2014	44	59	34	137
August 4, 2014	36	55	30	121
August 11, 2014	44	62	36	142
August 18, 2014	50	69	40	159
August 25, 2014	36	48	31	114
September 1, 2014	28	56	31	116
September 8, 2014	70	118	85	273
September 15, 2014	68	120	90	279
September 22, 2014	51	97	64	212
September 29, 2014	79	162	108	348
October 6, 2014	100	167	131	398
October 13, 2014	72	175	118	365
October 20, 2014	88	167	121	377
October 27, 2014	149	154	133	436
Total*	**6,865**	**12,812**	**9,694**	**29,371**

* Totals may not add up due to rounding.

Attachment 5 - Energy Charge Revenue

SURPLUS ENERGY PROGRAM
ENERGY CHARGE REVENUE

Week Beginning	Peak	Shoulder	Off-Peak	Total
November 1, 2013	$1,065	$3,036	$1,089	$5,191
November 4, 2013	$4,508	$7,092	$2,022	$13,621
November 11, 2013	$6,112	$11,433	$5,746	$23,291
November 18, 2013	$8,929	$11,942	$6,501	$27,372
November 25, 2013	$10,171	$11,604	$6,764	$28,538
December 2, 2013	$10,619	$16,200	$8,513	$35,332
December 9, 2013	$15,797	$18,911	$11,401	$46,109
December 16, 2013	$12,930	$20,529	$9,785	$43,244
December 23, 2013	$6,689	$18,407	$7,230	$32,326
December 30, 2013	$10,527	$19,707	$9,565	$39,798
January 6, 2014	$12,279	$18,067	$12,231	$42,577
January 13, 2014	$12,720	$19,396	$10,810	$42,926
January 20, 2014	$13,087	$18,532	$11,170	$42,789
January 27, 2014	$13,891	$18,386	$11,813	$44,090
February 3, 2014	$13,645	$21,955	$11,303	$46,903
February 10, 2014	$14,537	$21,614	$11,629	$47,780
February 17, 2014	$9,848	$20,937	$10,771	$41,556
February 24, 2014	$18,019	$24,875	$13,710	$56,604
March 3, 2014	$15,495	$21,435	$11,981	$48,912
March 10, 2014	$12,697	$16,627	$10,678	$40,001
March 17, 2014	$10,194	$14,478	$7,292	$31,964
March 24, 2014	$9,399	$13,020	$7,402	$29,821
March 31, 2014	$8,932	$12,173	$7,511	$28,616
April 7, 2014	$7,759	$12,756	$6,512	$27,027
April 14, 2014	$6,895	$11,717	$5,650	$24,262
April 21, 2014	$3,985	$9,131	$3,820	$16,936
April 28, 2014	$5,708	$8,372	$3,743	$17,823
May 5, 2014	$5,066	$6,922	$2,731	$14,720
May 12, 2014	$4,599	$7,757	$3,295	$15,652
May 19, 2014	$3,018	$5,714	$1,480	$10,212
May 26, 2014	$4,000	$3,903	$459	$8,362
June 2, 2014	$2,774	$3,116	$388	$6,278
June 9, 2014	$1,792	$764	$317	$2,872

SURPLUS ENERGY PROGRAM
ENERGY CHARGE REVENUE

Week Beginning	Peak	Shoulder	Off-Peak	Total
June 16, 2014	$1,620	$1,099	$196	$2,915
June 23, 2014	$1,674	$990	$142	$2,805
June 30, 2014	$1,388	$1,773	$240	$3,401
July 7, 2014	$2,602	$2,130	$354	$5,085
July 14, 2014	$1,795	$1,555	$244	$3,594
July 21, 2014	$1,720	$1,542	$244	$3,506
July 28, 2014	$1,586	$1,654	$249	$3,489
August 4, 2014	$1,526	$1,392	$187	$3,105
August 11, 2014	$1,789	$1,657	$218	$3,665
August 18, 2014	$2,044	$1,843	$244	$4,131
August 25, 2014	$1,467	$1,378	$366	$3,212
September 1, 2014	$1,075	$1,495	$375	$2,944
September 8, 2014	$2,315	$3,040	$1,008	$6,363
September 15, 2014	$2,006	$2,850	$967	$5,823
September 22, 2014	$1,135	$1,200	$385	$2,720
September 29, 2014	$1,771	$2,010	$650	$4,431
October 6, 2014	$853	$1,027	$639	$2,519
October 13, 2014	$337	$821	$553	$1,711
October 20, 2014	$375	$711	$517	$1,603
October 27, 2014	$1,412	$2,238	$924	$4,574
Total*	**$328,178**	**$482,912**	**$244,013**	**$1,055,103**

* Totals may not add up due to rounding.

Attachment 6 - Distribution Charge Revenue

SURPLUS ENERGY PROGRAM
DISTRIBUTION CHARGE REVENUE

Week Beginning	Peak	Shoulder	Off-Peak	Total
November 1, 2013	$190	$890	$595	$1,675
November 4, 2013	$1,021	$1,899	$1,423	$4,343
November 11, 2013	$857	$2,249	$1,603	$4,709
November 18, 2013	$1,286	$2,282	$1,807	$5,376
November 25, 2013	$1,367	$2,372	$1,830	$5,569
December 2, 2013	$1,382	$2,576	$1,934	$5,892
December 9, 2013	$1,629	$2,850	$2,217	$6,696
December 16, 2013	$1,507	$2,737	$2,109	$6,353
December 23, 2013	$872	$3,259	$2,049	$6,181
December 30, 2013	$1,290	$3,160	$2,194	$6,643
January 6, 2014	$1,482	$2,414	$1,972	$5,868
January 13, 2014	$1,387	$2,474	$1,965	$5,827
January 20, 2014	$1,462	$2,626	$2,050	$6,138
January 27, 2014	$1,540	$2,572	$2,065	$6,177
February 3, 2014	$1,422	$2,568	$1,993	$5,983
February 10, 2014	$1,480	$2,485	$2,033	$5,998
February 17, 2014	$1,021	$2,574	$1,833	$5,428
February 24, 2014	$1,499	$2,639	$2,073	$6,211
March 3, 2014	$1,279	$2,091	$1,758	$5,128
March 10, 2014	$1,165	$2,124	$1,692	$4,981
March 17, 2014	$1,097	$2,077	$1,644	$4,818
March 24, 2014	$1,217	$2,078	$1,730	$5,025
March 31, 2014	$1,156	$1,883	$1,618	$4,658
April 7, 2014	$899	$1,762	$1,455	$4,116
April 14, 2014	$884	$1,905	$1,531	$4,320
April 21, 2014	$641	$1,555	$1,225	$3,420
April 28, 2014	$723	$1,333	$1,111	$3,166
May 5, 2014	$637	$1,200	$982	$2,818
May 12, 2014	$628	$1,142	$973	$2,743
May 19, 2014	$369	$900	$653	$1,921
May 26, 2014	$411	$706	$525	$1,642
June 2, 2014	$341	$600	$444	$1,385
June 9, 2014	$280	$439	$358	$1,078

SURPLUS ENERGY PROGRAM
DISTRIBUTION CHARGE REVENUE

Week Beginning	Peak	Shoulder	Off-Peak	Total
June 16, 2014	$214	$328	$225	$767
June 23, 2014	$162	$256	$151	$568
June 30, 2014	$135	$313	$192	$640
July 7, 2014	$193	$341	$217	$751
July 14, 2014	$171	$243	$163	$577
July 21, 2014	$174	$267	$174	$615
July 28, 2014	$177	$264	$174	$615
August 4, 2014	$145	$263	$158	$566
August 11, 2014	$184	$287	$189	$660
August 18, 2014	$215	$344	$212	$771
August 25, 2014	$149	$217	$160	$527
September 1, 2014	$123	$274	$169	$567
September 8, 2014	$356	$657	$499	$1,511
September 15, 2014	$353	$673	$537	$1,562
September 22, 2014	$246	$520	$373	$1,139
September 29, 2014	$411	$929	$646	$1,986
October 6, 2014	$553	$954	$784	$2,291
October 13, 2014	$386	$1,004	$700	$2,090
October 20, 2014	$478	$956	$724	$2,158
October 27, 2014	$847	$883	$802	$2,532
Total*	**$40,093**	**$76,395**	**$58,692**	**$175,180**

* Totals may not add up due to rounding.

Attachment 7 - SEP Energy Revenues vs. Costs

SURPLUS ENERGY PROGRAM
SEP ENERGY REVENUES VS COSTS

Week Beginning	SEP Energy Sales (MWH)	SEP Sales*	Value of SEP Energy to MH	Total
November 1, 2013	277	$5,191	$5,421	($231)
November 4, 2013	724	$13,621	$5,966	$7,655
November 11, 2013	780	$23,291	$19,574	$3,718
November 18, 2013	888	$27,372	$27,544	($172)
November 25, 2013	921	$28,538	$26,480	$2,058
December 2, 2013	968	$35,332	$34,614	$718
December 9, 2013	1,093	$46,109	$48,888	($2,779)
December 16, 2013	1,037	$43,244	$39,137	$4,108
December 23, 2013	1,008	$32,326	$34,713	($2,387)
December 30, 2013	1,083	$39,798	$50,640	($10,841)
January 6, 2014	957	$42,577	$58,242	($15,665)
January 13, 2014	951	$42,926	$35,422	$7,504
January 20, 2014	1,002	$42,789	$54,042	($11,253)
January 27, 2014	1,009	$44,090	$91,481	($47,391)
February 3, 2014	977	$46,903	$65,336	($18,433)
February 10, 2014	979	$47,780	$66,750	($18,969)
February 17, 2014	886	$41,556	$31,204	$10,353
February 24, 2014	1,014	$56,604	$56,752	($148)
March 3, 2014	837	$48,912	$52,992	($4,080)
March 10, 2014	812	$40,001	$25,840	$14,162
March 17, 2014	786	$31,964	$26,826	$5,138
March 24, 2014	820	$29,821	$29,329	$492
March 31, 2014	760	$28,616	$22,604	$6,012
April 7, 2014	672	$27,027	$19,316	$7,710
April 14, 2014	714	$24,262	$17,770	$6,493
April 21, 2014	564	$16,936	$17,265	($329)
April 28, 2014	530	$17,823	$14,103	$3,720
May 5, 2014	478	$14,720	$15,513	($793)
May 12, 2014	466	$15,652	$2,024	$13,628
May 19, 2014	331	$10,212	$5,179	$5,033
May 26, 2014	289	$8,362	$2,727	$5,635
June 2, 2014	250	$6,278	$1,178	$5,101

SURPLUS ENERGY PROGRAM
SEP ENERGY REVENUES VS COSTS

Week Beginning	SEP Energy Sales (MWH)	SEP Sales*	Value of SEP Energy to MH	Total
June 9, 2014	203	$2,872	$2,442	$430
June 16, 2014	153	$2,915	$4,168	($1,253)
June 23, 2014	124	$2,805	$3,264	($459)
June 30, 2014	130	$3,401	$2,221	$1,180
July 7, 2014	158	$5,085	$3,563	$1,522
July 14, 2014	129	$3,594	$2,668	$926
July 21, 2014	134	$3,506	$2,410	$1,096
July 28, 2014	137	$3,489	$3,427	$62
August 4, 2014	121	$3,105	$3,031	$74
August 11, 2014	142	$3,665	$3,864	($199)
August 18, 2014	159	$4,131	$4,543	($412)
August 25, 2014	114	$3,212	$3,150	$61
September 1, 2014	116	$2,944	$2,937	$7
September 8, 2014	273	$6,363	$5,528	$835
September 15, 2014	279	$5,823	$3,579	$2,245
September 22, 2014	212	$2,720	$1,104	$1,616
September 29, 2014	348	$4,431	$1,562	$2,869
October 6, 2014	398	$2,519	$1,779	$740
October 13, 2014	365	$1,711	$1,642	$69
October 20, 2014	377	$1,603	$1,693	($90)
October 27, 2014	436	$4,574	$5,208	($633)
Total**	**29,371**	**$1,055,103**	**$1,068,652**	**($13,549)**

* Sales figures are based on the revenue received from the Energy Charge only. They do not include revenues from Distribution and Basic Charges.

** Totals may not add up due to rounding.

Manitoba Hydro

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pjramage@hydro.mb.ca

May 15, 2013

Mr. H. Singh
Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Singh:

RE: Public Utilities Board Order 43/13 - Interim Approval of Changes to the Curtailable Rate Program

On April 26, 2013, the Public Utilities Board of Manitoba ("PUB") issued Order 43/13 with respect to Manitoba Hydro's 2012/13 & 2013/14 General Rate Application. In this Order, the PUB approved the following, on an interim basis, with respect to Manitoba Hydro's proposed changes to its Curtailable Rate Program ("CRP"):

> *That Manitoba Hydro's proposed changes to the Curtailable Rate Program BE AND ARE HEREBY APPROVED ON AN INTERIM BASIS, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.*

Manitoba Hydro wishes to advise the PUB that two of the approved changes to the CRP are difficult to implement on an interim basis, as customer decisions in response to these changes are not easily reversible if these changes are not subsequently approved as final:

- A change in the defined hours for peak and off-peak periods; and,
- Elimination of Curtailment Options "C" and "CE" effective one year from PUB approval (i.e. the sunset date).

As the PUB is not prepared to approve these changes on a final basis at this time, Manitoba Hydro proposes to defer implementation of the change in the defined hours for peak and off-peak periods and the elimination of Options "C" and "CE" until such time as the PUB grants final approval.

Manitoba Hydro intends to implement the other changes to the CRP that were outlined in its Application, and approved by Order 43/13, in the intervening time. Manitoba Hydro notes that it will reduce the global subscription cap on Option "A", but only to the extent that the existing Option "C" load can be accommodated.

Manitoba Hydro is requesting the PUB's confirmation of the forgoing. Should you have any questions with respect to this submission, please do not hesitate to contact the writer at (204) 360-3946.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT

Per:

PATRICIA J. RAMAGE
Barrister and Solicitor

PJR/

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June 25, 2013

Ms. Patricia J. Ramage
Law Department
Manitoba Hydro
22nd floor, 360 Portage Avenue
Winnipeg, MB R3C 0G8

Dear Ms. Ramage:

Re: Public Utilities Board Order 43/13 Interim Approval of Changes to the Curtailable Rate Program

The Manitoba Public Utilities Board (Board) has received your letter of May 15, 2013 regarding the Board's interim approval of proposed changes to the Curtailable Rate Program (CRP) as ordered in Board Order 43/13.

In your letter Manitoba Hydro advises that Board that two of the proposed approved changes to the CRP are difficult to implement on an interim basis as customer's decisions in response to these changes are not easily reversible if these changes are not subsequently approved as final. Specifically, Manitoba Hydro highlights the following approved changes as problematic:

- A change in the defined hours for peak and off-peak periods; and'
- Elimination of the Curtailment Options "C" and "CE" effective one year from PUB approval (i.e. the sunset date).

Manitoba Hydro has proposed to defer the above changes until such time as the Board grants final approval to the proposed CRP changes. Manitoba Hydro is seeking the Board's confirmation that deferral of the above proposed changes to the CRP is acceptable to the Board.

The Board appreciates the uncertainty that may be created for CRP customers resulting from the Board's interim approval to the proposed CRP changes from Order 43/13. The Board therefore confirms Manitoba Hydro's proposed approach to defer the implementation of the above-referenced changes to the CRP program until such time as the Board grants final approval.

Yours truly,

"Original signed by"
K. Simonsen, P.Eng.
Associate Secretary

c.c. Bob Peters, Fillmore Riley
Roger Cathcart, Cathcart Advisory Services
Larry Buhr, LAB Consulting
Participants

Manitoba

CURTAILABLE RATE PROGRAM

FOR INDIVIDUAL CUSTOMER LOADS

PROPOSED

TERMS AND CONDITIONS

Manitoba Hydro

January 2015

TABLE OF CONTENTS

CURTAILABLE RATE PROGRAM
TERMS AND CONDITIONS

1. DEFINITIONS

The following expressions when used in these Terms and Conditions shall have the following meanings:

a) **"Billing Month"**: the period of time, generally 30 days, in which Energy and/or Demand is consumed and thereafter billed to the Customer.

b) **"Contingency"**: the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

c) **"Contingency Reserves"**: a component of Operating Reserves which are sufficient in magnitude and response and meet the North American Electric Reliability Corporation's (NERC) disturbance control standards. Contingency reserves are comprised of spinning and supplemental reserves.

d) **"Curtailment"**: a reduction in the use of Energy by the customer, as initiated by Manitoba Hydro.

e) **"Curtailment Period"**: for Option 'A' and 'R' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" to the time the "notice to restore" is given; for Option 'C' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" plus one full hour to the time the "notice to restore" is given; for Option 'E' customers, from the start and stop times specified on the customer fax to curtail and restore load.

f) **"Curtailment Year"**: the 12-month period commencing upon implementation of the Terms and Conditions of the Curtailable Rate Program by Manitoba Hydro once approved by the Public Utilities Board.

g) **"Demand"**: the maximum use of power within a specified period.

h) **"Disturbance":** An unplanned event that produces an abnormal system condition; a perturbation to the electric system; or an unexpected change in the supply-demand balance that is caused by the sudden failure of generation or interruption of load.

i) **"Energy"**: power integrated over time and measured or expressed in kilowatt-hours (kWh).

j) **"Firm Load"**: load that is not considered interruptible (curtailable).

k) **"Interruption"**: discontinuance in the supply of Energy.

l) **"Load Factor"**: the ratio of a customer's average Demand over a designated period of time to the Customer's maximum Demand occurring in that period. Monthly Load Factor is found by calculating the ratio of Energy use (kWh) to highest Demand (kW) multiplied by time (usually measured at 730 hours):

$$LF = \frac{\text{Energy (kWh per month)}}{\text{Peak Demand (kW) x hours per month}}$$

m) **"MISO-MBHydro Contingency Reserve Sharing Group" or "MISO-MBHydro CRSG":** The Midwest Independent Transmission System Operator Inc. (MISO) and Manitoba Hydro balancing authorities collectively maintain, allocate, and supply operating reserves required for each entities' use in recovering from Contingencies or Disturbances on the transmission systems operated by either party. The group is established under the coordination agreement between MISO and Manitoba Hydro.

n) **"Point of Delivery":** the point at which the Corporation delivers electricity and beyond which electric service facilities (excluding meters and metering transformers) are supplied by and are the responsibility of the customer.

o) **"Power Factor":** the ratio of real power in watts of an alternating current circuit to the apparent power in volt-amperes, expressed as kW/kV.A.

p) **"Protected Firm Load (PFL)"**: the amount of load (expressed in kW) that the customer wishes to protect from being curtailed.

q) **“Peak”**: defined as all hours from 6:01 hours through 22:00 hours Monday through Friday inclusive excluding Statutory holidays

r) **“Off-Peak”**: all nighttime hours from 22:01 hours through 06:00 hours Monday through Sunday inclusive, and all hours from 0:01 hours to 24:00 hours on Saturdays, Sundays and Statutory holidays.

s) **“Operating Reserves”**: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of Spinning Reserves and Supplemental Reserves.

t) **“Operating Reserve - Spinning”**: The portion of Operating Reserve consisting of: generation synchronized to the system and fully available to serve load within the NERC defined disturbance recovery period following the Contingency or Disturbance event; or load fully removable from the system within the disturbance recovery period following the Contingency or Disturbance event.

u) **“Operating Reserve - Supplemental”**: The portion of Operating Reserves consisting of: generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the NERC defined disturbance recovery period following a Contingency or Disturbance event; or load fully removable from the system within the disturbance recovery period following a Contingency or Disturbance event.

v) **“Planning Reserves”**: The reserves needed to ensure that future load obligations at times of peak demand do not exceed supply resources.

w) **“Reference Discount”:** An amount credited to the customer each month for having Planning and/or Contingency Reserve load available.

x) **“Reserve Discount”**: An amount credited to the customer for energy curtailed each time Supplemental Reserve load is deployed under Option R.

2. CURTAILABLE LOAD OPTIONS

The following curtailable load options are available, however are subject to capacity limitations and durations as noted in Section 6:

Option 'A': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'C': Curtail within one hour of notice for a maximum of four hours per curtailment period.

Option 'R': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'E': Curtail within 48 hours of notice for a maximum of 10 days per curtailment period.

Additional description of limits on curtailments (e.g. maximum curtailments per year) is provided on Page 13.

Options 'A', 'C' or 'R' cannot be combined with each other but may be combined with Option 'E' to increase the discount. The terms and conditions of combined Options 'AE', 'CE' and 'RE' are combinations of the individual options (e.g. notice to curtail for 'AE' would be five minutes for Option 'A' curtailments and 48 hours for Option 'E' curtailments).

Customers may elect to designate part of their load as Option 'A' and another part of their load as Option 'R' provided the loads designated under each option are distinct from each other. Although the customer designates a specific portion of their load as Option 'R', Manitoba Hydro's System Operator may request a curtailment of less than the amount designated by the customer. The minimum load the Manitoba Hydro System Operator can request under Option 'R' is 5,000 kW. Manitoba Hydro will make best efforts to request a curtailment equal to the customer's contracted amount.

3. NOMINATION OF CURTAILABLE LOAD

A customer must have a minimum, nominal curtailable load of 5 MW. Customers have two options of nominating eligible curtailable load however customers designating curtailable load under Option 'R' must nominate the "Guaranteed Curtailment" option.

(i) Guaranteed Curtailment

A customer selecting this option must guarantee availability 95%[1] of the time during each curtailment year. Manitoba Hydro reserves the right to exclude customers from future participation in the program should they fail to meet this guaranteed requirement. The customer is required to nominate curtailable load equal to the amount of which is guaranteed to be reduced at the time requested. For example, a customer with a total load of 100 MW may nominate 10 MW as curtailable load and guarantee that when requested that 10 MW of load (or lesser amount if requested by Manitoba Hydro System Operator) will be shed. In order to honour this guarantee, the customer will be required to ensure that its load prior to curtailment would be such that it never falls below 10 MW plus whatever Firm Load the customer wishes to protect.

In the event the Customer is unable to have the full amount of guaranteed curtailable load available for dispatch, the Customer must provide Manitoba Hydro 48 hours verbal notice of an anticipated plant shutdown and must also notify Manitoba Hydro immediately of any unanticipated unavailability of curtailable load. The customer shall immediately notify Manitoba Hydro when the curtailable load is again available. Failure to do so will result in the same penalties as failure to curtail as outlined in Section 10.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = GC x $/kW Credit for selected option where,

GC = the customer's guaranteed curtailable load

NOTE: The monthly credit will not be applied if a customer fails to provide guaranteed curtailable load for a period greater than 10% of the hours in the

[1] The 95% availability means the customer must guarantee their designated curtailable load will be available for curtailment a minimum of 8,322 hours (8,760 hours x 95%) each curtailment year.

applicable calendar month. For example, a customer would have to have their guaranteed load available for a minimum of 648 hours in a 30-day month and 670 hours in a 31-day month. This will ensure that customers are not being paid a credit when they are shutdown for extended periods of time. The customer is still required however to maintain the 95% per year availability criteria as specified above.

(i) Curtail to Protected Firm Load

The customer nominates a Protected Firm Load below which curtailment will not occur. The curtailable portion of the customer load will be the load available above the Protected Firm Load at the time of curtailment request. With this type of nomination, there is a risk to Manitoba Hydro that there will be little or no load to curtail when a request is made: i.e. that the customer is operating at or below protected firm level when curtailment request is made.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = (PD-PFL) x LF x $/kW Credit for Selected Option where,

PD = the customer's highest demand (kW) in the Peak billing period in the billing month.

PFL = Protected Firm Load of the customer in kW.

LF = is the customer's overall load factor during the Peak billing period in the billing month and excluding any days during which the customer complied with a curtailment request.

At Manitoba Hydro's discretion customers with load factors less than 50% during Peak periods on the curtailable portion of the load may be required to guarantee curtailable load, i.e. to take up Option 3(i).

4. CURTAILABLE RATE DISCOUNT

A Curtailable customer's bill is reduced by the curtailable load discount, calculated in accordance with the "Reference Discount" appropriate to the curtailment option selected by the customer and the formula for determining curtailable load.

Customers selecting Curtailment Option ‘R’ will, in addition to the Reference Discount, receive a “Reserve Discount” amount for each curtailment initiated and successfully completed. The Reserve Discount credit will be calculated based on the following formula:

Reserve Discount = LR x Du x FD, where

LR = amount of load reduction (in kW) requested by Manitoba Hydro’s System Operator to the customer at the time of an Option ‘R’ curtailment

Du = duration of the curtailment (in hours)

FD = fixed discount amount, currently set at $0.04 [2] per kWh

If, for example, a customer contracts for 15,000 kW of Option ‘R’ load, but the Manitoba Hydro System Operator only requires 10,000 kW of curtailable load, the Reserve Discount will be calculated based only on the 10,000 kW regardless of whether or not the customer load drops by an amount greater than 10,000 kW. The Reference Discount however will be calculated in accordance with the formula provided in Section 3 (i).

5. USE OF CURTAILABLE LOAD

Reserves in the form of Curtailable Load can serve two general purposes. The first purpose is to minimize disruption to Firm Load in the event of a Contingency or Disturbance. Manitoba Hydro has a Contingency Reserve obligation to the MISO-MBHydro CRSG, or successor organization, to carry a pre-defined amount of Contingency Reserves, both Spinning and Supplemental, to respond to Contingencies and Disturbances in the MISO or Manitoba Hydro balancing areas.

The second purpose of Curtailable Load is to maintain a sufficient level of Planning Reserves and Operating Reserves to maintain reliable operation of the bulk electric system and compliance to NERC reliability standards.

2 The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Dependent on the Curtailment Option selected, Manitoba Hydro will curtail customers in response to system emergencies and to maintain Planning and Operating Reserves for the following reasons.

(i) Option ‘A’ and ‘C’ Curtailable Load

Manitoba Hydro will use curtailable load designated under Options ‘A’ and ‘C’, to meet reliability obligations only. These include:

- to re-establish the MISO-MBHydro CRSG’s or successor organization’s Contingency Reserves. Once Manitoba Hydro’s Contingency Reserves are deployed in response to a MISO-MBHydro CRSG’s Contingency or Disturbance, Manitoba Hydro is required to re-establish Contingency Reserves within 105 minutes of the event that triggered the commitment to supply the Contingency Reserve. A curtailment may be called to reestablish those reserves;

- to protect Manitoba Firm Load or firm exports, when Operating Reserves are insufficient to avoid curtailing Firm Load. This curtailment would be called prior to Manitoba Hydro curtailing Firm Load or firm exports; and

- as Planning Reserves to meet Manitoba Hydro or its firm export customers’ resource adequacy requirements.

(ii) Option ‘R’ Curtailable Load

The MISO-MBHydro (or successor organization) requires participants to maintain Contingency Reserves comprised of Spinning Reserves and Supplemental Reserves. Manitoba Hydro will use curtailable load designated under Option ‘R’ to deploy Manitoba Hydro’s Supplemental Reserves to the extent necessary, having first dispatched its own generation resources.

(iii) Option ‘E’ Curtailable Load

Curtailments under Option ‘E’ will be initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Option 'E' customers will be curtailed prior to Manitoba Firm Load and firm export sales.

6. MAXIMUM LEVEL OF CURTAILABLE LOAD

Manitoba Hydro, at its discretion, can limit the amount of curtailable load needed to maintain Planning and Operating Reserve levels. Load under Option 'C' will no longer be available as of one year from the date of approval of the Terms and Conditions by the Public Utilities Board (the "sunset" date). Load currently served under Option 'C' will either revert to Firm Load or, at the customer(s) discretion, revert to Option 'A' Load prior to the sunset date.

(i) Option 'A' Curtailable Load

The maximum amount of curtailable load needed under Option 'A' has been set at 180 MW assuming Option 'C' load converts to Option 'A'. If however, Option 'C' load converts to Firm Load, the cap for Option 'A' will be set at 150 MW. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(ii) Option 'R' Curtailable Load

The maximum amount of curtailable load needed under Option 'R' has been set at 50 MW, with a maximum number of participating customers at any time limited to three. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(iii) Option 'E' Curtailable Load

There is currently no limit proposed.

7. CONTRACTS AND TERMINATION NOTICE

(i) Discounts or credits offered by the program, as well as all other terms and conditions, are fixed from the date of approval by the Public Utilities Board unless superseded by a further order of the Public Utilities Board or unless the program is withdrawn by Manitoba Hydro.

(ii) Customers selecting the Curtailable Rate Program will be required to contract for the service. In the event that the Public Utilities Board mandates changes to the program, which in Manitoba Hydro's opinion are material, Manitoba Hydro and the customer will agree to amend the contract to incorporate the changes, failing which the contract shall terminate immediately.

(iii) Customers accepting Curtailable service for the first time may switch curtailment options (subject to capacity limitations) or switch to Firm service entirely within the first six months, unless they have entered into the Curtailable Rate Program from another interruptible rate program.

(iv) Customers who have participated in the program for a period in excess of six months may:

a) re-contract for another Curtailable Rate Option for the following changes by providing two months' written notice to Manitoba Hydro.

- switch from Option 'C' to Option 'A' prior to the sunset date ;
- add Option 'E' to any other Option

b) switch from Option 'R' to Option 'A' or from Option 'A' to Option 'R' by providing one year's written notice to Manitoba Hydro. Switching can only occur if provision allows (i.e. the maximum level of load in a particular Option will not be exceeded as per Section 6).

c) switch from Curtailable to Firm service by providing one year's written notice to Manitoba Hydro in which case Manitoba Hydro may convert the load from Curtailable to Firm service at any time during the one year notice period. The one-year notice will not apply when the customer's decision to withdraw from the program is a result of material changes mandated by the Public Utilities Board as outlined in Section 7 (ii). Customers who have switched from Curtailable to Firm service may not be permitted to switch back to Curtailable service for one year, provided Curtailable load is available as defined in Section 6.

(v) Customers may re-designate their Protected Firm Loads or Guaranteed Curtailable Load by providing 12 months' written notice to Manitoba Hydro. Decreases to Protected Firm Load and/or increases to Guaranteed Curtailable Load may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. The time period may be shortened if customers are decreasing their Protected Firm Load as a result of notification by Manitoba Hydro that additional Option 'R' curtailable load is available, as described in section 6 (ii). Customers increasing their Protected Firm Load and/or decreasing their Guaranteed Curtailable Load must maintain a minimum curtailable load of 5 MW per month.

8. MANNER OF NOTICE TO CURTAIL

(i) Option 'A' ,' C' and 'R' Customers

For Option 'A' and 'R' customers, the Notice to Curtail of five minutes means that the customer must reduce the load by the contracted curtailable amount or to the contracted firm amount within five minutes of the initiation from Manitoba Hydro. For Option 'C', the Notice to Curtail of one hour means that the customer must reduce the load within one hour from the time the "Notice to Curtail" is given.

Initiation will be by telephone or by an electronic signal sent to the customer by the Manitoba Hydro System Operator. Both the initiation signal and the load response will be recorded by Manitoba Hydro.

(ii) Option 'E' Customers

Manitoba Hydro will give Option 'E' customers notice in writing that their load may be curtailed when Manitoba Hydro expects to be short of firm energy supplies. Manitoba Hydro will provide not less than 30 days notice. Notice will be deemed received three days from the date of mailing; or if faxed or sent by electronic mail, on the date that it was sent.

After the notice period has been met, Option 'E' customers will be on standby and curtailable on 48 hours notice by fax or electronic mail. Manitoba Hydro will give Option 'E' customers notice in writing whenever their standby status is withdrawn.

9. DEMAND PRO-RATION FOR OPTION 'E" CUSTOMERS

Customers curtailed under Option 'E' will have their Demand Charge prorated on the curtailable portion of load to exclude the period during which an Option 'E' curtailment was in effect. For example, if the load were curtailed for ten days in December, the Demand Charge would be reduced by 10/31 or 32% and, as well, the curtailable credit would be applied. This additional discount would apply only during months of curtailment and only to that portion of load which is curtailable. This provision will not reduce the maximum demand established for the purposes of computing the demand ratchet.

10. ADDITIONAL CHARGES FOR FAILURE TO CURTAIL

(i) Option 'A' ,'C' and 'R' Customers

The first failure to curtail load on request in any contract period will not attract additional charges, but the customer will forego the discount for that month.

After the first failure, the following additional charges will apply. First subsequent failure in any 12-month period: loss of monthly discount plus additional charge equal to discount. Second and subsequent failure in any 12-month period: loss of discount and additional charge equal to 3x discount, at which time, Manitoba Hydro will have the right to exclude the customer from further participation in the program.

(ii) Option 'E' Customers

If the customer has elected to participate in Option 'E', in the event of a single failure to curtail load, Manitoba Hydro may in its own discretion exercise one of the following remedies:

a) the normal additional charges, as described in 10 (i); or

b) twenty-four hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery to be restricted to achieve the maximum load that should have been achieved by curtailment; or

c) if load limitation as described in 10 (ii) b) is, in Manitoba Hydro's opinion, not practical or reasonable, 24 hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery to be disconnected for the remainder of the period. Disconnection shall only take place after explicit written communication with the customer and only if, otherwise, Firm Load customers would be impacted.

11. DURATION OF CURTAILMENTS

Notwithstanding the maximum single curtailment duration provisions of each of the options, Manitoba Hydro will attempt to minimize the duration.

12. UNPLANNED INTERRUPTIONS

In addition to program curtailments for which notice is provided, customers will continue to be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra provincially.

CURTAILABLE RATE PROGRAM OPTIONS
AS OF APRIL 1, 2014
UNLESS SUPERCEDED BY FURTHER ORDER OF THE PUB

Discount to Demand Charge Expressed as Percentage of Reference Discount per kW/month.

OPTIONS	**TERMS AND CONDITIONS**					
	Minimum Notice to Curtail	Maximum Duration Per Curtailment	Maximum Daily Hours of Curtailment	Maximum Number Curtailments Per Year	Maximum Annual Hours of Curtailment	Discount as Percentage of Reference Discount
A	5 minutes	4-1/4 Hours	6 Hours (Oct 1 - Apr 30) 10 Hours (May 1 - Sep 30)	15 Curtailments	63.75 Hours	70%
C*	1 Hour	4 Hours	8 Hours	15 Curtailments	60.00 Hours	40%
E	48 Hours	10 Days	24 Hours	3 Curtailments	720.00 Hours	35%
R	5 minutes	4-1/4 Hours	10 Hours (Apr 1 – Mar 31)	25 Curtailments	106.25 Hours	70% + Reserve Discount
A & E	Combination	Combination	Combination	18 Curtailments	783.75 Hours	100%
C & E*	Combination	Combination	Combination	18 Curtailments	780.00 Hours	70%
R & E	Combination	Combination	Combination	28 Curtailments	826.25 Hours	100% + Reserve Discount

* Options ‘C’ and ‘CE’ will no longer be available as of the sunset date.

The Monthly Reference Discount shall equal A, and shall be adjusted on April 1st of each fiscal year by the annual inflation factor, where:

A = the amount of the Reference Discount which is related to the marginal value of capacity, expressed in Canadian Dollars. The Reference Discount of $3.36 per kW/month as of April 1, 2014 shall be adjusted each year by the Inflation Factor as defined below.

Inflation Factor = at the end of each fiscal year of Manitoba Hydro, the percentage change in the Consumer Price Index for Manitoba as recorded for the most recent set of 12 month periods for which data are available.

Reserve Discount: The fixed price to be paid for energy during curtailment under Option ‘R’ has been set at $0.04 per kW.h.

Manitoba Hydro

REPORT TO
THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2013 – MARCH 31, 2014

September 2014

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SUMMARY

This Curtailable Rate Program ("CRP") annual report covers the period from April 1, 2013 to March 31, 2014. During this period three customers participated in the program and 14 Option R curtailments were successfully initiated.

The Public Utilities Board ("PUB") Order 42/13 dated April 26, 2013 approved, on an interim basis, the CRP Reference Discount of $3.28/kW for fiscal 2013/14. Customers received monthly credits on their electrical bill for their participation in the program totaling $5,965,689 during this time.

Manitoba Hydro's 2012/13 & 2013/14 General Rate Application ("GRA") included proposed revisions to the Terms and Conditions of the Curtailable Rate Program. The main revisions included a reduction in the amount of Option A and Option R load available to customers, the elimination of curtailment Options C and CE; and a change to the hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering.

In Order 43/13, the PUB accepted, on an interim basis, Manitoba Hydro's proposed changes to the Terms and Conditions of the CRP. As two of the changes proposed by Manitoba Hydro could not be easily reversed if final approval of the rate setting process was not granted given the proposed changes to the Terms and Conditions, Manitoba Hydro requested to defer implementation of the change in the defined hours for Peak and Off-Peak periods, and the elimination of Curtailment Options C and CE until such time as the PUB grants final approval. Manitoba Hydro also advised that it would implement the other changes to the CRP accepted by Order 43/13, including reducing the global subscription cap on Option A, but only to the extent that Option C load can still be accommodated. By letter dated June 25, 2013, the PUB accepted Manitoba Hydro's proposal.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period from April 1, 2013 to March 31, 2014 took effect on April 1, 2013.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. Manitoba Hydro's application to revise the CRP Terms and Conditions included a reduction to available Option A and C load from 230 MW to 178 MW and available Option R load from 100 MW to 50 MW. There is no limit for Option E load. The revised caps do not affect current CRP customers. Upon final approval of the changes to the Terms and Conditions, the Option C customer will have one year to decide if they wish to convert their load to Option A or to firm service. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the most vulnerable. Options A and C curtailable load in these hours increases the amount of capacity for sale in the export markets while Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

Curtailable load provides risk mitigation benefits to the power system. Curtailable load can be used to avoid shedding firm load and/or breach of North American Electric Reliability Council (NERC) standard(s) by Manitoba Hydro or the Midwest Independent System Operator-Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2]. Option R curtailable load allows Manitoba Hydro to meet reserve obligations thereby freeing

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[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009.

up hydro generation for market transactions in the short-term opportunity energy market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional sales. Without Option R capacity in place energy would be spilled. With Option R load, the additional energy generated can be sold at on-peak prices.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not initiate load curtailments in order to facilitate an opportunity spot market sale[4].

PERFORMANCE FOR 2013/14

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic levels.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a capacity sale.

The three customers that participated in the Curtailable Rate Program during the April 1, 2013 to March 31, 2014 period designated a total of 228 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 67 MW Option A, 31 MW Option C and 50 MW Option R. The amount each customer designated as curtailable load in relation to their total load varies, and therefore, impacts their curtailable credit, as shown on the following table:

Summary of Curtailment Credit Data April 1, 2013 to March 31, 2014					
Customer	**Option(s)**	**CRP Load as % of Total Load**	**Average On-Peak MW**	**Average On-Peak LF**	**Average Monthly Cr.**
1	A, R, E	87%	194.0	94.3%	$447,671
2	A	94%	24.5	93.6%	$49,469
3	C	0%	7.1	60.2%	$0

Customer 1: 87% of total load represents 41% Option AE, 26% Option R and 20% Option A for 2013/14.

Customer 3: this customer was operating below their protected firm load and therefore had no load available for curtailment.

Load designated under Option R must be nominated as a Guaranteed Curtailment. That is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Implementation and Size of Curtailments:

There were 14 Option R curtailments during the April 1, 2013 to March 31, 2014 period, all of which were initiated in response to a contingency or disturbance event requiring deployment of Manitoba Hydro's supplemental reserves. The following table summarizes the duration and load in MW of each curtailment.

April 2013 to March 2014	Option 'R'	
	Hrs	**MW**
April 18, 2013	0.63	50
April 19, 2013	0.25	50
April 25, 2013	0.77	50
May 27, 2013	1.77	50
June 6, 2013	0.70	50
June 21, 2013	1.37	50
July 3, 2013	0.93	50
July 3, 2013	1.55	50
July 7, 2013	1.43	50
July 17, 2013	0.73	50
August 19, 2013	1.72	50
September 3, 2013	0.23	50
February 5, 2014	3.05	50
March 27, 2014	0.75	50
Total	**15.88**	**N/A**
Average	**1.13**	**50**

All curtailments occurred during peak hours. The customer did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use telephone to communicate curtailment requirements to customers on the program. This procedure is manageable and provides the additional security that curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the 14 curtailments during this reporting period.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the “Reference Discount.” The Reference Discount is related to the marginal value of capacity, and is adjusted on April 1 of each year by the inflation factor. The Reference Discount in effect for the reporting period April 1, 2013 to March 31, 2014 was $3.28 per kW/month, as approved by the PUB, on an interim basis, in Order 42/13 dated April 26, 2013. Option AE customers receive 100% of the discount, while Option A and R customers receive 70% of the discount or $2.30 per kW/month. Option C customers receive 40% of the discount or $1.31 per kW/month.

For curtailable load nominated as 'Protect to Firm Load' the Reference Discount is calculated and credited to customers' bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a 'Guaranteed Curtailment' the Reference Discount is calculated and credited to customers' bill each month as GC x D where,

GC = the customer's guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount represents the value of carrying contingency reserves and is calculated and credited to customers' bill for each successful curtailment as LR x Du x FD where,

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Control to the customer at the time of an Option R curtailment
Du = duration of the curtailment (in hours)
FD[5] = fixed discount amount, currently set at $0.04 per kWh

The table below illustrates the amount of the monthly Reference Discount Credit that each customer received from April 1, 2013 to March 31, 2014, as well as their monthly On-Peak Demand and On-Peak Load Factor.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	208.8	92.6%	$439,020	24.6	97.6%	$51,875	31.7	59.4%	$0
May	207.8	83.9%	$408,342	24.9	93.7%	$50,388	28.6	39.5%	$0
June	175.5	93.8%	$443,042	24.6	92.5%	$49,159	19.0	6.1%	$0
Jul	175.5	97.7%	$456,860	24.6	94.7%	$50,350	0.7	70.1%	$0

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Aug	175.5	97.4%	$455,635	24.8	98.1%	$52,438	0.7	69.9%	$0
Sep	175.5	95.7%	$449,584	24.7	67.8%	$36,131	0.7	74.4%	$0
Oct	175.5	95.7%	$449,654	24.3	95.8%	$50,310	0.8	56.5%	$0
Nov	209.3	93.9%	$443,462	24.1	99.5%	$51,754	0.8	68.1%	$0
Dec	205.9	92.8%	$439,684	24.4	97.7%	$51,475	0.9	76.7%	$0
Jan	207.0	97.6%	$456,335	24.3	95.6%	$50,168	0.9	46.0%	$0
Feb	205.9	96.4%	$452,137	24.1	96.1%	$50,011	0.4	78.2%	$0
Mar	205.9	94.8%	$446,540	24.3	94.4%	$49,575	0.4	78.1%	$0
Total	**2,328.0**	**94.3%**	**$5,340,296**	**293.8**	**93.6%**	**$593,633**	**85.5**	**60.2%**	**$0**

The discounts shown for Customer 1 do not include the $31,760 credited in respect of the Option R Reserve Discount.

Adequacy of Terms and Conditions:

Manitoba Hydro proposed revisions to the Terms and Conditions of the Curtailable Rate Program as part of its 2012/13 & 2013/14 GRA. The revisions included:

- a reduction in the amount of Option A and Option R load available to customers;
- elimination of curtailment Options C and CE;
- change in hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering;
- removal of the monthly variation to nominate curtailable or firm load; and
- exclusion from the program after a customer's 2nd failure to curtail in a 12 month period.

In Order 43/13, dated April 26, 2013, the PUB accepted the proposed revisions as noted above, on an interim basis. Subsequent to the receipt of that Order, Manitoba Hydro, in its letter dated May 15, 2013, informed the PUB of the difficulty in implementing a change in the defined Peak and Off-Peak hours, and elimination of Option C and CE on an interim basis, and proposed that these changes be deferred until such matters can be finalized. The PUB, in its letter dated June 25, 2013, confirmed Manitoba Hydro's proposed approach.

The Terms and Conditions have protected Manitoba Hydro's contingency reserves and provided operating reserves that satisfy the requirements of NERC and the MISO-MB Hydro CRSG.

CONCLUSION

The Curtailable Rate Program facilitates fulfilling Manitoba Hydro's commitment of carrying, deploying, and re-establishing contingency reserves to meet its obligations with the MISO-MBHydro CRSG and to maintain compliance to NERC Standards. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

CRP continues to fulfill Manitoba Hydro's obligations, and with the above mentioned changes to the Terms and Conditions, will preserve the value of the program to both Manitoba Hydro and its customers.

ATTACHMENT 1

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD TO MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to an estimate of the marginal cost of firm, long-term capacity. Over the long term, a representative value for capacity can be developed by estimating the annual carrying cost (includes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity to Manitoba Hydro, which is a simple cycle combustion turbine (SCCT). In 2005 the annual carrying cost of a SCCT was estimated to be $78 per kW per year, or $6.50 per kW per month, evaluated at load. It was proposed that this cost would escalate at the rate of inflation. This cost was reviewed in 2012 and was found to be appropriate going forward. This approach has the advantage of providing a clear transparent value, which is also stable over time and is consistent with the approach that is utilized to evaluate the benefits of other resource options such as DSM that may have a capacity component.

Curtailable load is less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place, a SCCT can be relied upon as a permanent, long-term resource, unlike curtailable load which can be terminated with a notice period of one year. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to the Manitoba Hydro system. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the period around the 2023/24 time period, when the requirement to add generation to serve domestic customers may be expected to occur with 2013 planning assumptions and base demand side management program assumptions. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

The economic benefits of curtailable load can vary considerably year to year for a number of reasons. In the case of Option R CRP, the economic benefits derived from this option will vary depending on water conditions. Export market conditions can also impact the value of curtailable load to Manitoba Hydro. In the MISO market, current supply and demand conditions for capacity resources can cause variability in the near term value of capacity resources. Use of a longer-term levelized value maintains stability in CRP pricing, therefore sheltering the CRP customer from these sources of variability.

As described above curtailable load is less valuable than a SCCT because it has limited dispatchability, is not sustainable in reducing load over longer periods, and is not guaranteed to exist in the long term. Therefore in order to reflect these factors, curtailable load is assigned a long-term levelized value that is 42% of the annual carrying cost of a SCCT. After consideration of inflation subsequent to the 2011 base year, this yields an estimate of benefits for the year beginning April 1, 2013 of $3.28 per kW/month, which is referred to as the "Reference Discount". This value would apply to the curtailable rate option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

REPORT TO

THE PUBLIC UTILITIES BOARD

LIMITED USE OF BILLING DEMAND

2013/14

September 2014

Manitoba Hydro

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REPORT TO PUBLIC UTILITIES BOARD ON THE LIMITED USE OF BILLING DEMAND RATE OPTION

SUMMARY

This report on the Limited Use of Billing Demand ("LUBD") rate option covers the period April 1, 2013 to March 31, 2014. During this period there were 81 customers on the LUBD rate, of which 59 are classed as General Service Small, 16 are General Service Medium, and 6 are General Service Large.

The LUBD rate option, implemented on July 1, 2000, is a rate option that Manitoba Hydro offers to address the concerns of low load factor customers. These customers, if billed on standard General Service Demand rates, are affected by high demand charges in comparison to relatively low energy use, resulting in a high cost of energy per kilowatt-hour. Customers on LUBD have a lower impact on the system peak compared to the overall General Service class, as is evident by their low winter coincidence factor of 31%.

Billing on LUBD rates as opposed to standard General Service Demand rates has saved LUBD customers approximately $290,000 during the 2013/14 fiscal year. This represents annual savings of approximately $3,600 per LUBD customer or $300 per customer per month.

BACKGROUND

In Order 91/00, dated June 30, 2000, the Public Utilities Board of Manitoba ("PUB") approved Manitoba Hydro's LUBD program, on an interim basis, as a temporary rate offering for a two-year period commencing July 1, 2000. The program became a permanent rate offering in Order 116/08 dated July 29, 2008, when the PUB granted final approval of the terms and conditions of the LUBD and directed Manitoba Hydro to file status reports on the LUBD rate option on an annual basis.

The LUBD rate was introduced to address the high unit energy costs faced by a relatively small number of customers with very low load factors. These customers, who set high demands relative to their overall energy use, were opposed to paying high demand charges when they used little energy. Under the program, customers could opt for a lower demand charge in exchange for a higher energy charge. Demand charges are intended to recover at least a portion of the utility's costs incurred to meet the peak load that do not vary with a customer's consumption. The LUBD rate option recognizes that low load factor customers, as a group, have a much lower ratio of coincidence with system peak periods than typical General Service customers, and therefore, the cost associated with meeting the peak of low-load factor customers is lower.

DESCRIPTION

The LUBD rate was designed such that demand customers would be indifferent between this rate and the standard General Service rate for which they otherwise qualify at a billing load factor of approximately 18%. At billing load factors less than 18%, customers could reduce their overall bills by paying a higher energy charge in exchange for a lower demand charge.

There is no change in the Basic Charge or determination of the Billing Demand when customers choose LUBD over standard rates.

ELIGIBILITY

All General Service Demand customers are eligible for the LUBD rate but only those customers with low energy use relative to their billing demand will benefit from selecting this option. Customer savings depend on the manner in which the business operates and consumes energy. This means that two customers with the same average annual billing load factor may not see the same results, and a lower annual billing load factor does not necessarily mean more savings. For example, a GS Small Demand customer who exceeds 50 kV.A in only a few months of the year may save little in Demand Charges if they are on LUBD (and pay for all energy at the higher LUBD Energy rate) compared to a customer with an identical billing load factor that exceeds 50 kV.A by a significant margin in most or all months of the year.

LUBD customers who elect to convert back to the standard General Service Rate are not eligible to participate in the LUBD rate option for the next 12 months.

CUSTOMER PARTICIPATION

There were a total of 81 customers that billed on the LUBD rate in the 2013/14 fiscal year, an overall decrease of 2 customers from the 2012/13 fiscal year.

The majority of customers on LUBD continue to be in the General Service Small Demand rate class as shown in Table 1 which provides a summary of the number of customers, by rate class, participating in the LUBD rate option in 2013/14:

Table 1

Rate Class	No. of Customers
General Service Small	59
General Service Medium	16
General Service Large (750 V to 30 kV)	3
General Service Large (> 100 kV)	3
Total	**81**

In the 2013/14 fiscal year, the majority (approximately 85%) of LUBD customers had an annual billing load factor of 20% or less, as shown in Table 2. Customers with a load factor over 20%, or customers not benefiting on LUBD, are referred to their Manitoba Hydro Representative for review.

Table 2:

Billing Load Factor	No. of LUBD Customers
0% - 5%	19
6% - 10%	15
11% - 15%	24
16% - 20%	11
over 20%	12
Total	**81**

The billing load factors for LUBD customers are considerably lower than billing load factors associated with typical General Service customers. Based on 2013/14 billing data, the billing load factor for regular General Service customers was 45% for GS Small Demand, 53% for GS Medium, 59% for GS Large 750 V to 30 kV, and 80% for GS Large > 100 kV.

Load Research data for 2012/13 indicates that the peak coincidence factor for the LUBD class is also lower than the class average peak coincidence factor, as shown in Table 3 below:

Table 3:

Rate Class	Summer Coincidence Factor %	Winter Coincidence Factor %
LUBD	42%	31%
GSS Demand	89%	91%
GSM	91%	92%
GSL 750 V - 30 kV	89%	90%
GSL > 100 kV	57%	77%

Customers participating in LUBD represent 29 different industry types as defined by Statistics Canada and listed in Table 4. The majority of customers fall in the category of "Other Utility Industries" which typically represents water and waste pumping stations. Other major industry types include Amusement/Recreational Services, Agriculture, and Wood industries. These four industries represent 41% of the LUBD customers.

Table 4:

Industry Type	# of Customers
Accommodation	1
Agriculture	8
Amusement and Recreational Services	8
Auto. Vehicles, Parts, Sales & Service	1
Business Services	1
Chemical and Chemical Products	1
Education	3
Electrical and Electronic Products	1
Fabricated Metal Products	4
Furniture and Fixtures	1
Industrial and Heavy Construction	2
Local Government	1
Membership Organizations	2
Metals, Hardware, Plumb, Heat, Wholesale	2
Miscellaneous Government	2
Non-Metallic Mineral Products	1
Other Products, Wholesale	5
Other Service Industries	3
Other Utility Industries	10
Paper and Allied	1
Plastic Products	3

Industry Type	**# of Customers**
Primary Metals	1
Printing, Publishing & Allied	1
Real Estate Operators	2
Refined Petroleum and Coal Products	1
Storage and Warehousing	5
Transportation	1
Transportation Equipment	2
Wood	7
Total	81

FINANCIAL IMPACTS

For 2013/14, the total savings to customers on the LUBD rate option, compared to the standard General Service rate, was approximately $290,000 ($3,600 per customer or $300 per customer month). Of the 81 customers, 58 benefited during the 12 month period while 23 customers paid more in comparison to the standard General Service rate. These 23 accounts have been referred to their Manitoba Hydro Representative for review. The majority will likely stay on LUBD as the loss for the year was minimal and there is potential for savings in the future given the nature of their usage. Four customers however have switched off LUBD and are now billing under the standard General Service rate, while another service has since been removed.

Table 5 provides a comparison of the revenue billed to LUBD customers versus what they would have been billed had they remained on the standard General Service rate based on the 2013/14 fiscal year. Table 6 provides a distribution of the number and percentage of LUBD customers by average monthly savings (loss) realized through their participation in the LUBD rate offering in 2013/14.

Table 5:

Rate Class	**As Billed on LUBD**	**If Billed as Standard GS**	**Annual Difference**
General Service Small	$ 372,873	$ 447,704	$74,832
General Service Medium	$ 442,035	$ 546,103	$104,068
General Service Large (750 V to 30 kV)	$ 71,283	$ 91,696	$20,412
General Service Large (> 100 kV)	$ 131,304	$ 222,108	$90,804
Total	**$1,017,495**	**$1,307,612**	**$290,116**

Table 6:

Average Monthly Savings (Loss)	No. of LUBD Customers	% of LUBD Customers
Over $1,501	2	2%
$1,001 - $1,500	4	5%
$501 - $1,000	10	12%
$201 - $500	15	19%
$101 - $200	7	9%
$0 - $100	21	26%
$(1) - $(50)	15	19%
$(51) - $(100)	5	6%
Over $(100)	2	2%
Total	**81**	**100%**

CONCLUSION

The LUBD rate was designed to provide an electricity rate option for customers with low billing load factors and it is generally performing as anticipated. The revenue impact to Manitoba Hydro of billing customers under the LUBD instead of the respective General Service Demand rates is modest at approximately $290,000 for the last fiscal year.

Manitoba Hydro

PO Box 815 • Winnipeg, Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3257 • Fax / N° de télécopieur : (204) 360-6147 • baczarnecki@hydro.mb.ca

June 23, 2014

Mr. H. Singh
Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Singh:

RE: Manitoba Hydro Roadway Lighting Conversion Program- Application for Interim Light Emitting Diode Rates for the Area and Roadway Lighting Class

Manitoba Hydro's efforts toward pursuing Demand Side Management ("DSM") opportunities were reviewed extensively by the Public Utilities Board ("PUB") and other parties at the recently concluded Needs for and Alternatives To ("NFAT") proceeding. The importance of Manitoba Hydro's investment in DSM to meet Manitoba's future electricity demand in the most economic manner and to assist customers with managing their energy bills was acknowledged by all parties. Manitoba Hydro remains committed to continuing its aggressive pursuit of all economic DSM opportunities to meet these goals.

During the NFAT proceeding, Manitoba Hydro introduced its 2014 to 2017 Power Smart Plan ("the Plan"), which includes aggressive new energy efficiency targets that will see investments in the utility's Power Smart programs more than double over the next three years. One of the commercial initiatives included in the Plan is the Light Emitting Diode ("LED") Roadway Lighting Conversion Program (the "LED Conversion Program"), which Manitoba Hydro will launch in the summer of 2014.

The Corporation is requesting the approval of new LED rates that will allow Manitoba Hydro to effectively introduce this program, and contribute toward the successful attainment of the Power Smart targets outlined in the Plan.

Information with respect to the LED Conversion Program and the achievement of Power Smart energy conservation targets related to the improved efficiency of LED streetlights compared with the current HPS streetlight technology is provided herein for the PUB's consideration in approving new rates for this program.

Manitoba Hydro's LED Roadway Lighting Conversion Program

Manitoba Hydro has been pursuing energy efficient opportunities in the area of lighting for over 20 years, through its Commercial Lighting Program and its past Roadway Lighting Conversion and Residential Compact Fluorescent Lighting programs. As a continuation of these efforts, the LED Conversion Program will retrofit existing High Pressure Sodium ("HPS") roadway lights to LED fixtures over a seven year period. The LED roadway lighting fixtures will consume approximately 40 percent less electricity compared to HPS lighting, and as such, the LED Conversion Program will assist Manitoba Hydro in achieving its Power Smart energy conservation targets.

LED technology produces a more direct white light and has a 20 year product life, while HPS technology produce a yellow/orange light and has only a 5 year product life. In 2013, Manitoba Hydro began conducting pilot replacements with 44 HPS roadway lights being converted to LED on nine streets in Winnipeg and Thompson, which resulted in total annual energy savings of over 9,000 kWh. These pilot projects enabled Manitoba Hydro to monitor the product performance of different LED manufacturers, the light outputs, and general customer feedback. To date, Manitoba Hydro has not experienced any performance issues or issues with public acceptance of the lighting.

In addition to the energy cost savings and efficiencies LEDs will derive for Manitoba Hydro, LED fixtures will also improve the efficiency mandates of a number of municipalities in the Province. To that end, the Association of Manitoba Municipalities ("AMM") recently passed a resolution to lobby Manitoba Hydro for the provision of LED lighting options when replacing and/or installing lighting fixtures. The AMM resolution with respect to LED Street Lighting is provided as Attachment 1 to this Application.

Manitoba Hydro will launch its LED Conversion Program in the summer of 2014, and in working with Manitoba municipalities and local governments, will convert all HPS roadway lighting (less than 1000W) to energy efficient LED technologies over the next 7 years. The program is expected to achieve 35 GWh in electricity savings and 5 MW in winter peak demand savings by 2020/21, and is expected to reduce Manitoba Hydro's street-light maintenance costs of single light out calls by approximately $800,000 annually once the entire conversion program has been fully implemented.

Proposed LED Rates

Manitoba Hydro is requesting PUB approval, on an interim basis, to implement LED rates for the Area and Roadway Lighting Class. Manitoba Hydro does not currently have rates in place for LED roadway lighting fixtures. The new LED rates are required at this time in order to accurately and appropriately charge customers for services provided under Manitoba Hydro's Area and Roadway Lighting rate schedule, given the initiation of the replacement of HPS lighting with LED lighting fixtures beginning in the summer of 2014.

Attachment 2 provides the supporting calculations for the proposed LED rates. Manitoba Hydro derived the proposed LED rates by determining the annual kilowatt hour savings expected to be achieved by converting from HPS lighting to LED and then determining the monthly cost savings using the Area and Roadway Lighting Energy charge from Manitoba Hydro's 2013 Prospective Cost of Service Study (PCOSS 13) updated to reflect actual rate increases for September 1, 2012, May 1, 2013, and May 1, 2014. The monthly cost savings were then deducted from the approved HPS rates effective May 1, 2014, to determine the proposed LED rates.

Attachment 3 provides the proposed rate schedules (pages 18 and 19) for rates effective August 1, 2014, which include proposed LED rates for the Area and Roadway Lighting class. The proposed rates will apply to all LED installations, including new installations and those related to the replacement of existing HPS fixtures.

Manitoba Hydro has also provided a copy of this Application to Area and Roadway Lighting customers that will benefit from the new LED rates, namely the City of Winnipeg and the Association of Manitoba Municipalities.

Should you have any questions with respect to the foregoing, please do not hesitate to contact the writer at 204-360-3257.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent A. Czarnecki
Barrister & Solicitor
BAC/
encl.

Resolutions

AMM Resolution #26-2013

Manitoba Hydro LED Street Lighting

Sponsor(s)	Department(s)
Tache, RM (Eastern)	Manitoba Hydro

THEREFORE BE IT RESOLVED THAT the Association of Manitoba Municipalities lobby Manitoba Hydro to provide LED lighting options to municipalities when replacing and/or installing lighting fixtures.

Manitoba Hydro | **Attachment 2**
Application for Interim LED Rates | **June 23, 2014**

NEW RATE NAME		HPS Category	HPS Wattage	LED Wattage	Wattage Savings	kW Savings	Annual Hours	Annual kWh Savings	Energy Rate	Annual Energy Savings	Per Month Savings	Approved Monthly HPS Rate	Proposed Monthly LED Rate
10 LED (20w CF Equivalent)	Exclusive	20 W CF	20	12.5	7.5	0.008	4252	31.9	$0.05287	$1.69	$0.14	$2.13	$1.99
60 LED (70w HPS Equivalent)	Shared	70	97	58.2	38.8	0.039	4252	165.0	$0.05287	$8.72	$0.73	$7.60	$6.87
60 LED (70w HPS Equivalent)	Exclusive	70	97	58.2	38.8	0.039	4252	165.0	$0.05287	$8.72	$0.73	$12.48	$11.75
60 24 hrs LED (70w 24 hrs HPS Equivalent)	Exclusive	70	97	58.2	38.8	0.039	4252	165.0	$0.05287	$8.72	$0.73	$14.03	$13.30
80 LED (100w HPS Equivalent)	Shared	100	135	81	54.0	0.054	4252	229.6	$0.05287	$12.14	$1.01	$7.89	$6.88
80 LED (100w HPS Equivalent)	Exclusive	100	135	81	54.0	0.054	4252	229.6	$0.05287	$12.14	$1.01	$13.16	$12.15
110 LED (150w HPS Equivalent)	Shared	150	190	114	76.0	0.076	4252	323.2	$0.05287	$17.09	$1.42	$9.67	$8.25
110 LED (150w HPS Equivalent)	Exclusive	150	190	114	76.0	0.076	4252	323.2	$0.05287	$17.09	$1.42	$14.86	$13.44
180 LED (250w HPS Equivalent)	Shared	250	300	180	120.0	0.120	4252	510.2	$0.05287	$26.98	$2.25	$12.32	$10.07
180 LED (250w HPS Equivalent)	Exclusive	250	300	180	120.0	0.120	4252	510.2	$0.05287	$26.98	$2.25	$17.13	$14.88
280 LED (400w HPS Equivalent)	Shared	400	470	282	188.0	0.188	4252	799.4	$0.05287	$42.26	$3.52	$14.14	$10.62
280 LED (400w HPS Equivalent)	Exclusive	400	470	282	188.0	0.188	4252	799.4	$0.05287	$42.26	$3.52	$23.77	$20.25
280 2/100' LED (400w 2/100' Equiv)	Exclusive	400	470	282	188.0	0.188	4252	799.4	$0.05287	$42.26	$3.52	$36.75	$33.23
280 4/100' LED (400w 4/100' Equiv)	Exclusive	400	470	282	188.0	0.188	4252	799.4	$0.05287	$42.26	$3.52	$26.99	$23.47

	¢/kWh
2.5% Sept 1, 2012 ARL Increase	2.50%
3.5% May 1, 2013 ARL Increase	3.50%
2.75% May 1, 2014 ARL Increase - Approved	2.75%
Projected Cummulative Rate Increases	9.00%
2012/13 ARL Energy Cost (PCOSS13) at April 1, 2012 Rates	4.850
Projected PCOSS Energy Rate	5.287

AREA AND ROADWAY LIGHTING

OUTDOOR LIGHTING

LEGEND

I	Incandescent
F	Fluorescent
CF	Compact Fluorescent
LED	Light Emitting Diode
MH	Metal Halide
MV	Mercury Vapour
HPS	High Pressure Sodium Vapour
Q	Quartz

Exclusive Pole:	A corporate-owned pole for the primary purpose of supporting outdoor lighting devices.
Shared Pole:	A pole of the primary purpose of supporting electrical circuits other than outdoor lighting.

AREA AND ROADWAY LIGHTING

(Incandescent and Mercury Vapour are NOT available for new installations)

OUTDOOR LIGHTING RATE - *TARIFF NO. 2014-80:*

Watts	Rate Per Month	
	Shared	Exclusive
200 F	-	$ 9.93
20 CF	-	$ 2.13
100 I	$ 4.57	$ 9.93
150 I	-	$ 9.93
300 I	-	$ 14.16
500 I	$ 11.96	$ 19.51
400 MH	-	$ 23.77
175 MV	$ 8.84	$ 14.16
250 MV	$ 10.12	$ 16.03
400 MV	$ 13.88	$ 19.17
70 HPS	$ 7.60	$ 12.48
70 HPS 24 hours	-	$ 14.03
100 HPS	$ 7.89	$ 13.16
150 HPS	$ 9.67	$ 14.86
250 HPS	$ 12.32	$ 17.13
400 HPS	$ 14.14	$ 23.77
400 HPS 2/100'	-	$ 36.75
400 HPS 4/100'	-	$ 26.99
750 HPS	$ 21.91	$ 34.76
1 000 HPS	-	$ 40.32
1 000 HPS 1/60'	-	$ 41.25
1 000 HPS 2/100'	-	$ 49.44
1 000 HPS 4/100'	-	$ 42.40
10 LED	-	$ 1.99
60 LED	$ 6.87	$ 11.75
60 LED 24 hours	-	$ 13.30
80 LED	$ 6.88	$ 12.15
110 LED	$ 8.25	$ 13.44
180 LED	$ 10.07	$ 14.88
280 LED	$ 10.62	$ 20.25
280 LED 2/100'	-	$ 33.23
280 LED 4/100'	-	$ 23.47

Applicability: The Area and Roadway rate is available throughout the Province of Manitoba and applies to area and roadway lighting installed by agreement for public authorities.

Manitoba Hydro
June 23, 2014

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

SURVEY OF CANADIAN ELECTRICITY BILLS – MAY 1, 2014

http://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/utility_rate_comp.shtml

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

ELECTRIC LOAD FORECAST

INDEX

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

ELECTRIC LOAD FORECAST

7.0 OVERVIEW

Tab 7 provides a summary of the 2014 Electric Load Forecast.

The province of Manitoba is growing, both in population and economically, resulting in more housing and in increases in related services within the commercial sector. Economic growth results in the anticipated expansion associated with commercial and industrial customers. Together, forecast population and economic growth result in a Manitoba load that is expected to grow in all sectors.

This Tab provides information on both current load and load growth assumptions. Manitoba Hydro considers all available options for meeting the energy needs of Manitobans, including both demand-side resources and supply-side resources as discussed in Tab 9. The current Demand Side Management plan, as detailed in Tab 8, is combined with the load forecast to represent the forecast net load, which is used to forecast general consumers revenue in MH14.

7.1 ELECTRIC LOAD FORECAST SUMMARY

The Electric Load Forecast provides a long term projection of future electricity demand in Manitoba with a forecast provided for both energy and capacity requirements. The load forecast is reviewed and updated on an annual basis as part of the annual corporate planning cycle. A copy of the 2014 Electric Load Forecast is provided in Appendix 7.1.

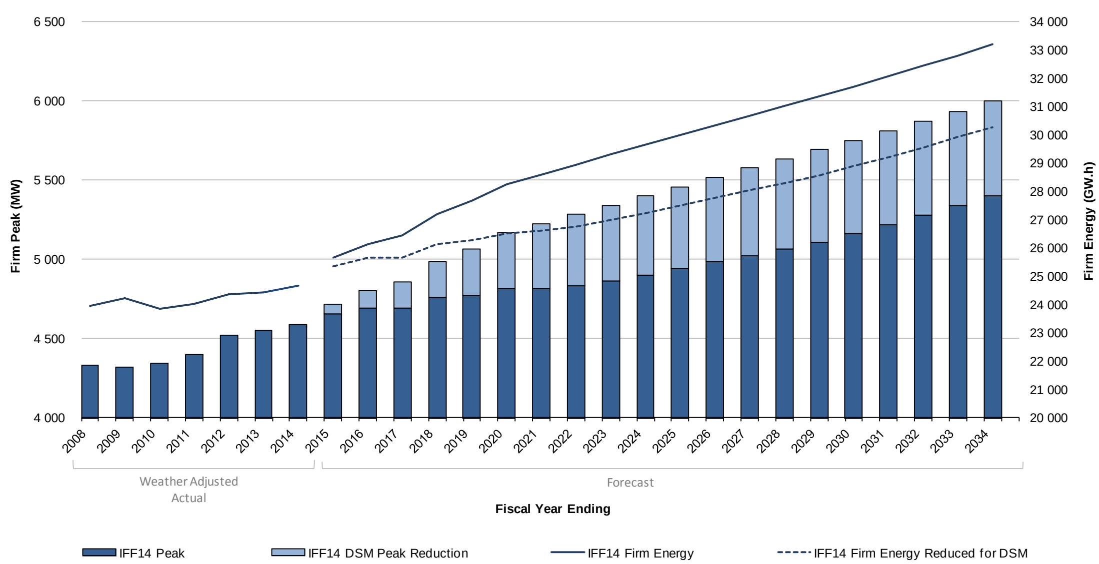
Manitoba load is forecast for the following sectors: Residential, General Service – Mass Market, General Service – Top Consumers, Losses and Station Service, and Miscellaneous. The Residential and General Service markets combined represent the majority of energy use in Manitoba.

The 2014 Load Forecast reflects the following with respect to Demand Side Management (“DSM”):

- Historical load values include the effect of Manitoba Hydro's past DSM efforts, including both improvements to energy codes and standards, as well as past market-based Power Smart programs.
- Forecast load values reflect the future impact of implemented or committed energy codes and standards, but not future activity under market–based DSM programs.
- Forecast future activity under market-based DSM programs has not been removed from the 2014 Load Forecast. The energy savings forecast to be achieved through future market-based DSM programs are considered in the Peak and Energy demand information provided in Tab 9 of the Application.

The figure below provides the forecast growth in Manitoba Hydro's load, as well as the reduction to forecast load growth including the impacts of the forecast DSM activities. Manitoba Hydro's DSM initiatives are described in detail in Tab 8 of the Application.

Figure 7.1



The figures in section 7.1 below compare the 2014 Electric Load Forecast to the forecast adjusted for the DSM Savings attributable to the future market-based DSM Programs.

Manitoba Hydro continually seeks to enhance the forecast and its supporting methodologies. The load forecast is produced annually to take into account changes in the markets as well as new outlooks into the future. This allows the planning process at

Manitoba Hydro to make annual adjustments to account for incremental changes and adjust for longer-term trends. A comparison describing the changes between the 2013 Electric Load Forecast and the 2014 Electric Load Forecast can be found in the 2014 Electric Load Forecast (Appendix 7.1) starting at page 12. The description of the methodology can be found in the 2014 Electric Load Forecast starting on page 59.

7.1 Residential Sector

Historical Period (1994/95 - 2013/14):

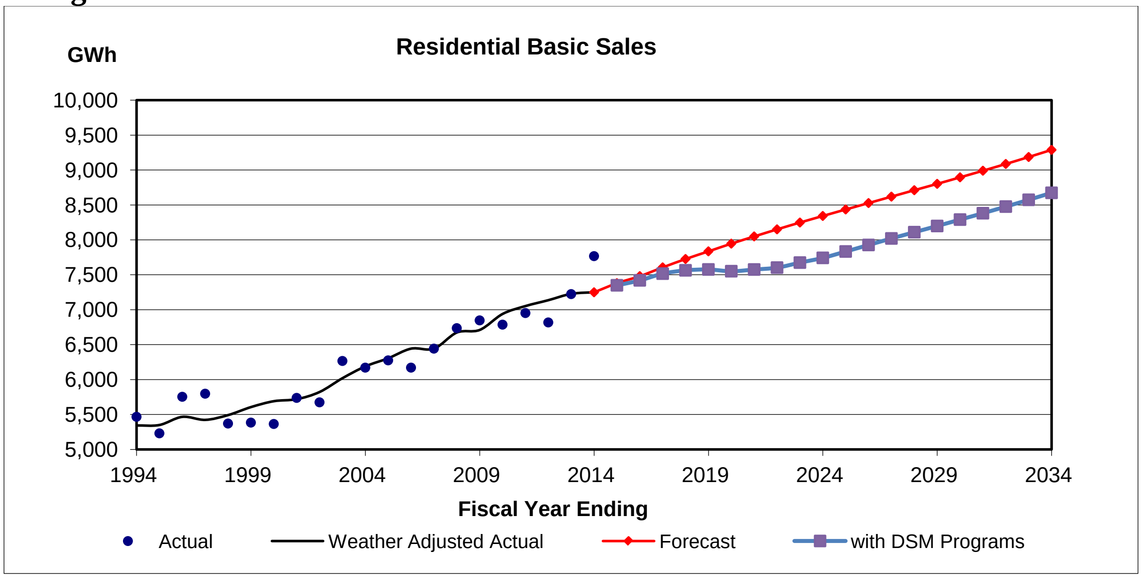
The residential sector had minimal growth during the 1990's but growth has been steady since about 1999. During the last 20 years, weather adjusted Residential consumption has been growing at an average of 100 GWh or 1.6% per year. This growth reflects the effects of past improvements in energy efficiency codes and standards and past participation in Power Smart programs.

Forecast Period (2014/15 – 2033/34):

Over the forecast period, the Residential sector is expected to grow by 102 GWh or 1.2% per year. This is primarily due to anticipated growth in population which accounts for 1% of the growth. The increase in average use per customer is expected to add 0.2% to the annual growth. With the inclusion of energy savings to be achieved through Power Smart programs, the overall net Residential growth is expected to be 71 GWh or 0.9% per year.

Figure 7.2 below provides a graphical representation of the historical and forecast usage of the Residential sector.

Figure 7.2- Residential Sales



Note: Sales forecast at meter.

7.2 General Service Sector

Historical Period (1994/95 - 2013/14):

During the past 20 years, the General Service sector overall has grown 203 GWh or 1.7% per year on a weather-adjusted basis. This growth reflects the effects of past improvements in energy efficiency codes and standards and past participation in Power Smart programs.

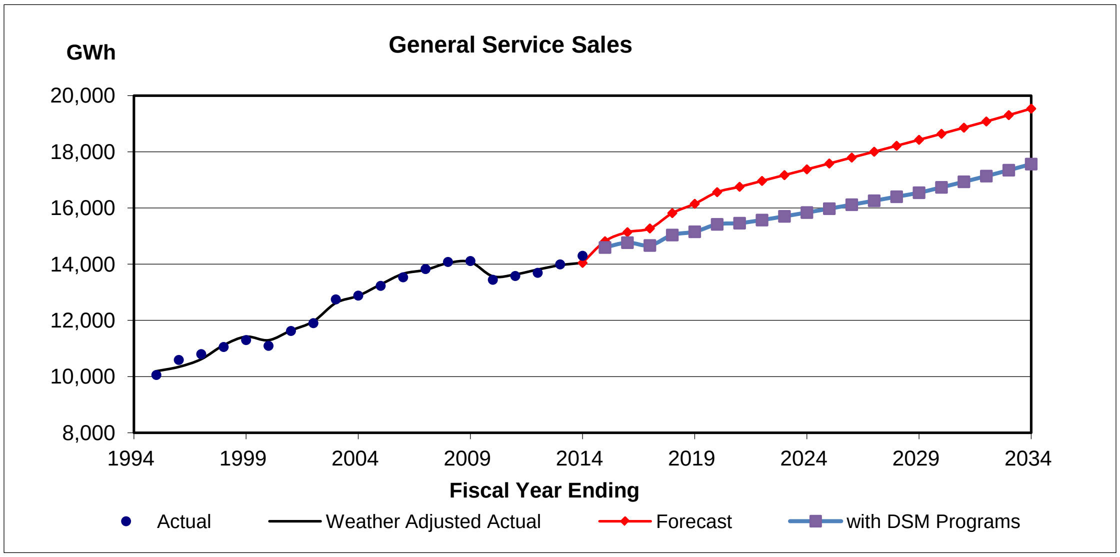
The General Service sector primarily consists of two categories of consumers: Mass Market and Top Consumers. Mass Market has grown steadily at an average of 117 GWh per year or 1.6%. The Top Consumers are more sensitive to economic conditions and were growing at an average of 173 GWh per year until the onset of the economic downturn of 2009/10. During 2009/10 and 2010/11, the Top Customers decreased 741 GWh and excluding the loss of one Top Consumer, have since recovered and resumed normal operations.

Forecast Period (2014/15 – 2033/34):

Growth in the General Service sector is forecast to grow 274 GWh or 1.7% per year over the forecast period. Mass Market is expected to contribute 142 GWh per year of projected growth with Top Consumers contributing the remaining 132 GWh per year. This includes the anticipated short term committed load growth in the Pipeline sector, minor growth in other Top Consumers and an expected Top Consumer load decrease. The inclusion of Power Smart programs lowers General Service growth to 176 GWh or 1.1% per year.

Figure 7.3 below provides a graphical representation of the historical and forecast usage of the General Service sector.

Figure 7.3- General Service Sales



Note: Sales forecast at meter.

7.3 Gross Firm Energy

Gross Firm Energy includes all electricity that is generated to meet firm energy requirements for all customers within Manitoba and excludes non-firm (interruptible load).

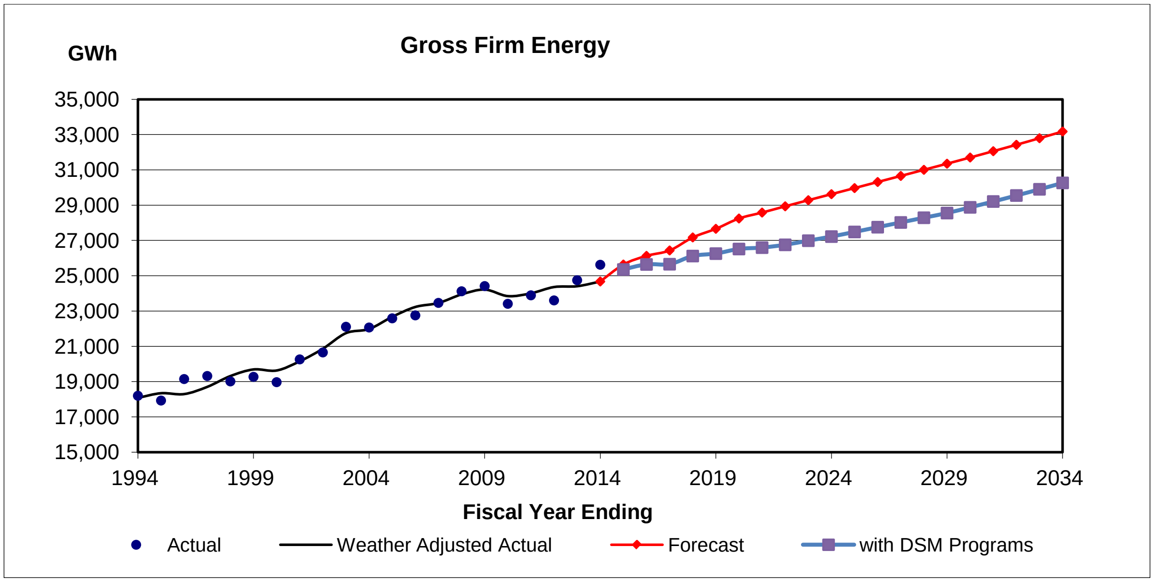
Historical Period (1994/95 - 2013/14):

During the past 20 years, Gross Firm Energy has grown 333 GWh or 1.6% per year on a weather-adjusted basis. The trend in Gross Firm Energy growth has been relatively consistent over the period and reflects the effects of past improvements in energy efficiency codes and standards and past participation in Power Smart programs. As noted earlier, the economic downturn had a significant impact on some General Service Top Consumers in 2009/10 and was the main reason for the decline that year; however, since then excluding the loss of one Top Consumer, this sector has since recovered and resumed normal operations.

<u>Forecast Period (2014/15 – 2033/34)</u>:
During the forecast period, Gross Firm Energy is expected to grow 425 GWh or 1.5% per year. The inclusion of Power Smart programs will lower Gross Firm Energy growth to 279 GWh or 1.0% per year.

Figure 7.3 below provides a graphical representation of the historical and forecast usage of Gross Firm Energy.

Figure 7.4- Gross Firm Energy



Note: Energy forecast at generation.

7.4 Gross Total Peak

The Gross Total Peak is the maximum hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and diesel customers with curtailed loads added back in. The term "integrated" indicates that the average load within the peak hour is used.

<u>Historical Period (1994/95 - 2013/14)</u>:

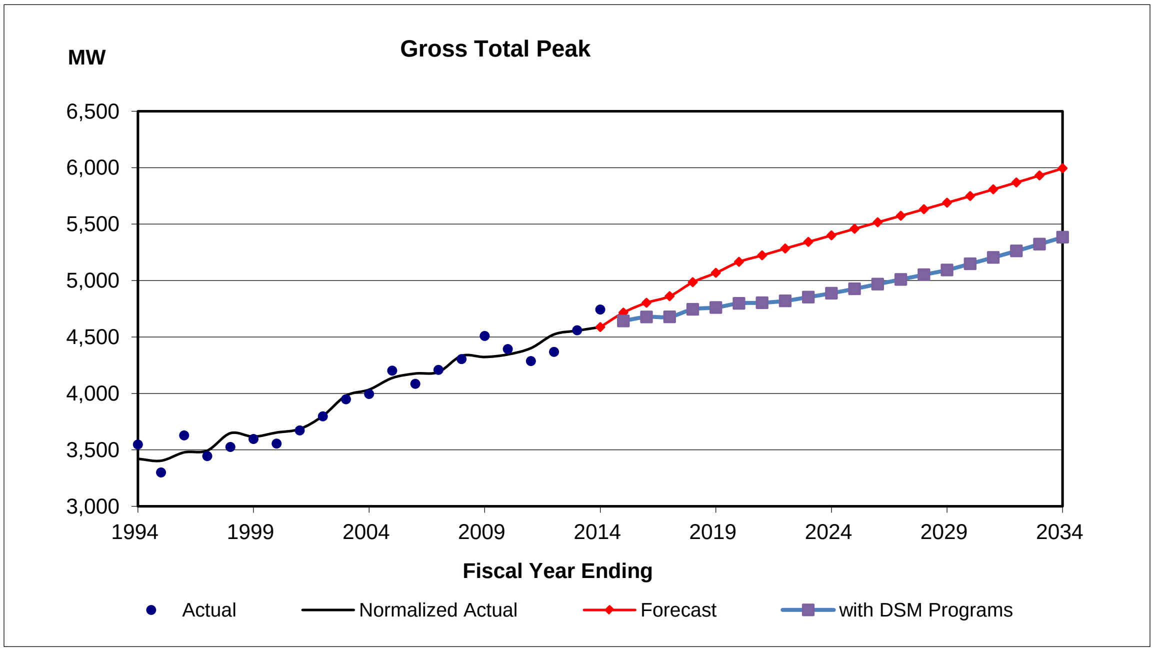
During the past 20 years, Gross Total Peak has grown 62 MW or 1.6% per year on an adjusted basis. Gross Total Peak has grown significantly since 2000/01, reflecting the general growth in energy load over that period.

<u>Forecast Period (2014/15 – 2033/34)</u>:

During the forecast period, Gross Total Peak is projected to grow 70 MW or 1.3% per year. The inclusion of Power Smart programs will lower the demand growth to 40 MW or 0.8% per year.

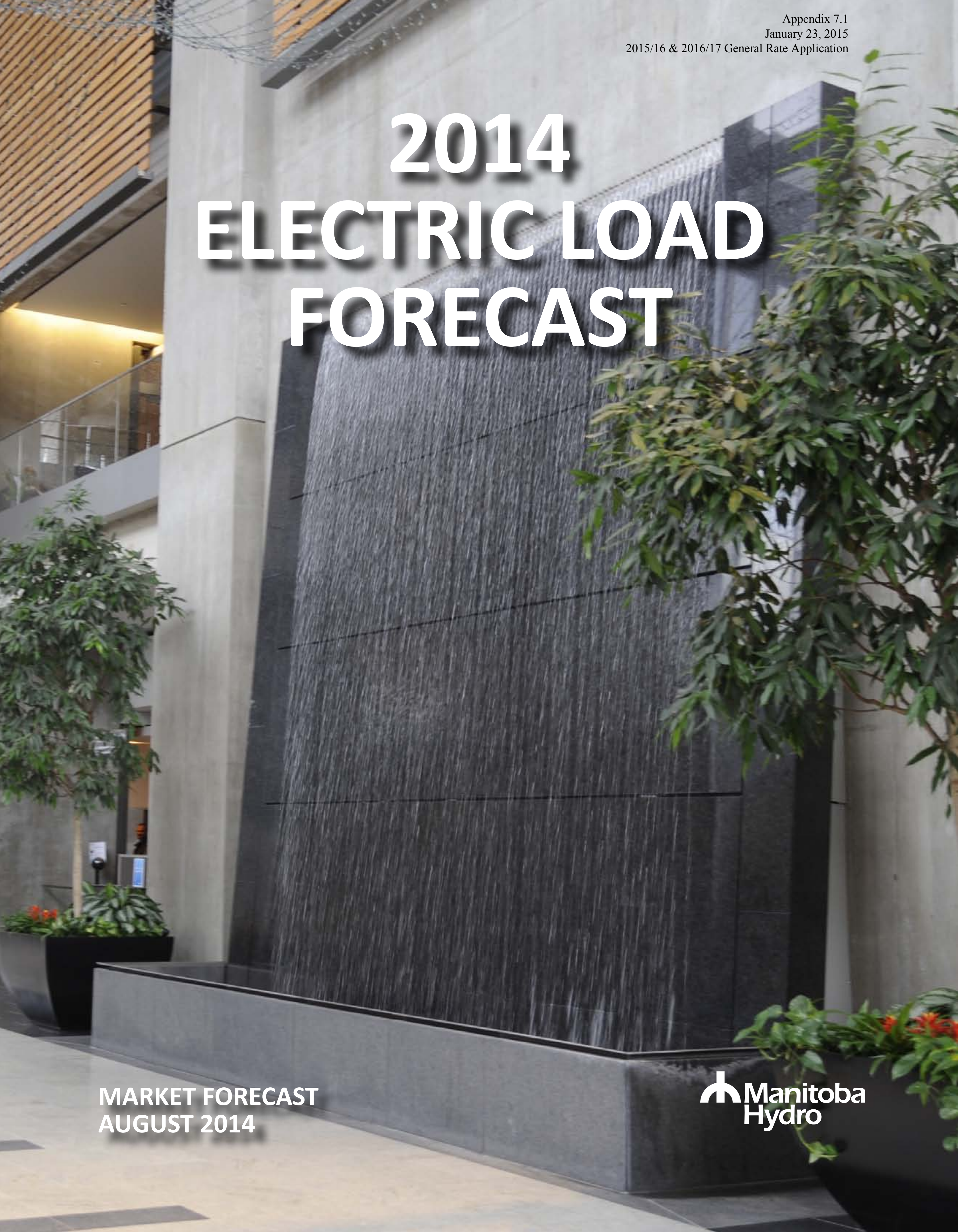
Figure 7.5 below provides a graphical representation of the historical and forecast of Gross Total Peak.

Figure 7.5- Gross Total Peak



Note: Peak forecast at generation.

2014 ELECTRIC LOAD FORECAST



MARKET FORECAST
AUGUST 2014

Manitoba Hydro

EXECUTIVE SUMMARY

Overview

The Gross Firm Energy in Manitoba is forecast to grow from a weather adjusted value of 24,677 GW.h in 2013/14 to 29,626 GW.h in 2023/24. This average growth is 495 GW.h or 1.8% per year for 10 years. By 2033/34, Gross Firm Energy is forecast to be 33,177 GW.h, a twenty-year growth rate of 425 GW.h or 1.5% per year.

Gross Total Peak is forecast to grow at about the same pace, growing 81 MW or 1.6% a year for the next 10 years, and 70 MW or 1.3% a year for the next 20 years. In 20 years, the peak will grow 1,408 MW to 5,995 MW.

Growth is expected in all sectors. The 20 year growth rates in the Residential Basic, General Service Mass Market and General Service Top Consumers sectors are forecast to be 1.2%, 1.4% and 2.0% respectively.

During the last 10 years, Gross Firm Energy has grown 269 GW.h or 1.2% per year. This ten year period includes the 2009 economic downturn that slowed growth.

The primary driver of growth in Manitoba is the population, with the secondary driver being the economy. Manitoba Hydro's 2014 Economic Outlook provides both the forecast of the population and the resulting forecast of Residential Basic customers that is used in this document. The population of Manitoba has grown from 1,166,000 people in 2003/04 to 1,269,000 people in 2013/14, averaging 0.9% growth per year. The forecast is that Manitoba's population will grow to 1,542,000 by 2033/34, averaging 1.0% per year. The primary reason for the expected increase of population growth in Manitoba is due to the Provincial Nominee Program which will continue to sustain moderate annual growth in immigrants.

Residential Basic customer growth is expected to mimic population growth, growing 1.0% per year over the next 20 years. An increase in average use per customer adds 0.2% to the growth and is primarily due to increased use of electric space and electric water heating in dwellings.

General Service Mass Market is forecast to grow at an average 1.4% per year, comparable to its historic growth of 1.4% per year over the past ten years.

General Service Top Consumers is forecast to grow at 2.0% per year. This is higher than its 0.1% growth per year during the past ten years which included the loss of a customer and an economic downturn. But it is less than the 3.5% growth per year during the prior ten years. Combined, the 20 year historical growth of the Top Consumers has been 1.9% per year. Short term committed loads include 1,194 GW.h of growth in the Pipeline sector, an expected top consumer load decrease of 494 GW.h, and other top consumer increases totaling 401 GW.h.

Change Between the 2013 and 2014 Forecast

The Gross Firm Energy in 2013/14 was 562 GW.h less than forecast in 2013 due to a temporary load loss of two Top Consumers. By 2019/20, the 2014 forecast is 850 GW.h higher due to increases to Top Consumers in the Pipeline sector and a higher Residential customer forecast in the earlier years. By 2032/33 the increase in the 2014 forecast is reduced to 129 GW.h due to an reduction in the Residential customer forecast and increases to the projected impacts of Codes and Standards. This equates to a 0.4% increase in the forecast of 2032/33, which represents a gain of less than half a year of load growth (1 year = approximately 425 GW.h).

The Gross Total Peak forecast in 2032/33 is down 28 MW compared to the 2013 Load Forecast, less than a half a year of load growth (1 year = approximately 70 MW).

Load Sensitivities and Extreme Events

The effect of alternate assumptions has been quantified for sensitivity or scenario analysis:

	Annual Energy Effect (GW.h)	Peak Effect (MW)
1% Increase/Decrease in Population	± 130	± 24
1% Increase/Decrease in Income and GDP	± 125	± 23
1% Increase/Decrease in Electricity Price	∓ 62	∓ 11
1% Increase/Decrease in Gas to Electricity Price Ratio	± 0.5	± 0.1
Climate Change per Degree Celsius Warmer	+ 23	- 47
If 0% or 100% of Residential had Electric Space Heat	-2,733, +4,796	-891, +1,564
If 0% or 100% Residential had Electric Water Heat	-892, +928	-102, +106
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	- 846	- 156
Additional Load if 100% Electric Vehicle Saturation Rate	+ 4,172	+ 289
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 1,824	-104

(For comparison, 1 year of load growth is approximately 425 GW.h or 70 MW)

Table 1 - Gross Energy and Peak

GROSS FIRM ENERGY AND GROSS TOTAL PEAK

History and Forecast
2003/04 - 2033/34

	Gross Firm Energy		Gross Total Peak		Load Factor
Fiscal Year	(GW.h)	Growth (%)	(MW)	Growth (%)	(%)
2003/04	22,069		3,994		63.1%
2004/05	22,589	2.4%	4,201	5.2%	61.4%
2005/06	22,757	0.7%	4,085	-2.8%	63.6%
2006/07	23,464	3.1%	4,208	3.0%	63.7%
2007/08	24,122	2.8%	4,304	2.3%	64.0%
2008/09	24,417	1.2%	4,509	4.8%	61.8%
2009/10	23,412	-4.1%	4,393	-2.6%	60.8%
2010/11	23,892	2.1%	4,286	-2.4%	63.6%
2011/12	23,605	-1.2%	4,367	1.9%	61.7%
2012/13	24,750	4.9%	4,559	4.4%	62.0%
2013/14	25,625	3.5%	4,743	4.0%	61.7%
2013/14 Wadj	24,677	-3.7%	4,587	-3.3%	61.4%
10 Year Avg Gr.	269	1.2%	55	1.3%	
2014/15	25,639	3.9%	4,716	2.8%	62.1%
2015/16	26,130	1.9%	4,803	1.8%	62.1%
2016/17	26,436	1.2%	4,861	1.2%	62.1%
2017/18	27,174	2.8%	4,985	2.6%	62.2%
2018/19	27,662	1.8%	5,068	1.7%	62.3%
2019/20	28,247	2.1%	5,166	1.9%	62.4%
2020/21	28,583	1.2%	5,223	1.1%	62.5%
2021/22	28,937	1.2%	5,284	1.2%	62.5%
2022/23	29,284	1.2%	5,342	1.1%	62.6%
2023/24	29,626	1.2%	5,400	1.1%	62.6%
10 Year Avg Gr.	495	1.8%	81	1.6%	
2024/25	29,970	1.2%	5,458	1.1%	62.7%
2025/26	30,316	1.2%	5,516	1.1%	62.7%
2026/27	30,659	1.1%	5,574	1.0%	62.8%
2027/28	31,006	1.1%	5,632	1.0%	62.8%
2028/29	31,352	1.1%	5,690	1.0%	62.9%
2029/30	31,703	1.1%	5,748	1.0%	63.0%
2030/31	32,061	1.1%	5,808	1.0%	63.0%
2031/32	32,424	1.1%	5,869	1.0%	63.1%
2032/33	32,796	1.1%	5,931	1.1%	63.1%
2033/34	33,177	1.2%	5,995	1.1%	63.2%
20 Year Avg Gr.	425	1.5%	70	1.3%	

***Note: History and historic growth rates include DSM. Forecast and forecasted growth rates exclude DSM.**

Table 2 - Change in Energy and Peak

GROSS FIRM ENERGY AND GROSS TOTAL PEAK Change from Previous Forecast 2014/15 - 2033/34						
	Gross Firm Energy			Gross Total Peak		
Fiscal Year	2014 Forecast (GW.h)	2013 Forecast (GW.h)	Change (GW.h)	2014 Forecast (MW)	2013 Forecast (MW)	Change (MW)
2013/14 Act	25,625			4,743		
Weather Adj.	-948			-155		
2013/14 Wadj	24,677	25,239	(562)	4,587	4,601	(14)
2014/15	25,639	25,676	(37)	4,716	4,680	36
2015/16	26,130	26,013	117	4,803	4,742	61
2016/17	26,436	26,322	114	4,861	4,801	60
2017/18	27,174	26,606	568	4,985	4,857	128
2018/19	27,662	27,003	660	5,068	4,930	138
2019/20	28,247	27,398	850	5,166	5,002	164
2020/21	28,583	27,789	794	5,223	5,074	149
2021/22	28,937	28,197	740	5,284	5,147	137
2022/23	29,284	28,605	679	5,342	5,222	120
2023/24	29,626	29,013	614	5,400	5,296	104
10 Year	495	377		81	70	
Avg Gr.	1.8%	1.4%		1.6%	1.4%	
2024/25	29,970	29,418	552	5,458	5,369	89
2025/26	30,316	29,822	493	5,516	5,443	73
2026/27	30,659	30,225	433	5,574	5,516	58
2027/28	31,006	30,625	380	5,632	5,588	44
2028/29	31,352	31,041	312	5,690	5,664	26
2029/30	31,703	31,453	251	5,748	5,739	9
2030/31	32,061	31,863	198	5,808	5,813	(5)
2031/32	32,424	32,265	159	5,869	5,886	(17)
2032/33	32,796	32,667	129	5,931	5,959	(28)
19 Year	427	391	36	71	71	-1
Avg Gr.	1.5%	1.4%	0.1%	1.4%	1.4%	0.0%

***Note: History includes DSM. Forecast and forecasted growth rates exclude DSM.**

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INTRODUCTION

This document is prepared annually as Manitoba Hydro's forecast of its future load requirements for its service area. The service area consists of all of Manitoba (99.85% of sales), as well as two resale customers that supply energy to Creighton, Sask. (0.12% of sales) and the Northwest Angle, Minn. (0.03% of sales). Exports of power to other utilities are not included.

This information is provided for several purposes. Short term forecasts of sales by billing month within rate groups are needed to forecast revenue for rate making, accounting and system operations. Long term forecasts of energy and peak is required by power planning to determine long term supply requirements.

A "customer" in this document refers to a metered electrical service. Unmetered services, such as flat rate water heating and sentinel rentals do not count as customers, and street lights group a number of services as one customer. A customer is not the same as a building. One building can have multiple electric services and may count as more than one customer, or multiple buildings may have only one service and may count as only one customer. A customer in this document is also not the same as a customer on the billing system. The latter is a person or organization that Manitoba Hydro serves. One billing customer may pay the bill for multiple services and thus count as multiple customers in this document.

Electric consumption is read from a customer's meter in units of kilowatt-hours (kW.h). A typical dwelling not using electricity for heating uses approximately 10,000 kW.h per year. This document reports electric use in terms of gigawatt-hours (GW.h). One GW.h equals one million kW.h, which is approximately the energy of 100 typical dwellings not using electricity for heating.

The highest load requirement for a time period is known as the peak load. It is given in terms of megawatts (MW). One MW equals one thousand kilowatts (kW). A typical dwelling not using electricity for heating would use a maximum of about 2.5 kW sometime during the year. However, dwellings will not all be at their maximum use at the same hour. The use of all dwellings at any specific hour is known as the coincident load. The coincident peak is the load at the hour of Manitoba's system peak. A typical dwelling not using electricity for heating would use about 1.6 kW at the coincident peak. Therefore 1 MW is approximately the coincident peak requirement of 600 typical dwellings not using electricity for heating.

Components of Manitoba's Electricity Use – 2013/14

General Consumers Sales (also referred to as Total Sales) includes the energy supplied to all of Manitoba Hydro's individually billed customers. Over the 2013/14 fiscal year, Manitoba Hydro averaged 552,660 General Consumers Sales customers who consumed 22,338 GW.h.

The major groups include

(1) Residential Basic, with 462,274 customers who used 7,767 GW.h or 34.8% of Sales. These are mostly residences that include single-family dwellings, multi-family dwellings and individual apartment suites.
(2) General Service Mass Market, with 66,569 customers who used 8,839 GW.h or 39.6% of Sales. These are small to large Commercial and Industrial customers.
(3) General Service Top Consumers, with 31 customers who used 5,461 GW.h or 24.4% of sales. These are 17 high-usage companies (some count as multiple customers) that are forecast individually.

The remaining customers include Seasonal customers (billed twice a year rather than monthly), Diesel customers (four remote towns not connected to the integrated grid system), Flat Rate Water Heating and Area and Roadway Lighting. Their electricity use totals only 271 GW.h or 1.2% of Total Sales. Over 50,000 of these services do not count as customers.

Manitoba Load at Common Bus is the total load metered at all the substations in the province that supplies Manitoba Hydro's non-Diesel customers and includes Distribution Losses and Construction Power. In 2013/14, Common Bus was 23,541 GW.h or about 5.4% more than Total Sales.

Gross Firm Energy is the total load needed to be generated for domestic firm load requirements on the Integrated System (excludes diesel). It includes Transmission Losses and Station Service. Some customers are on non-firm contracts (Surplus Energy Program), and their load is not included as part of Manitoba Hydro's generation requirement. In 2013/14, Gross Firm Energy was 25,625 GW.h or about 14.7% more than Total Sales.

Table 3 - Components of Manitoba Electricity Use

COMPONENTS OF MANITOBA ELECTRICITY USE 2013/14 (Customers, Actual Consumption and Average Use)				
Forecast Group	Cust/Serv	GW.h	% of Sales	kW.h/cust
Residential Basic	462,274	7,767	34.8%	16,802
Residential Diesel	583	9	0.0%	14,791
Residential Seasonal	20,757	92	0.4%	4,455
Residential Flat Rate Water Heating	3,858	20	0.1%	5,080
Total Residential	483,613	7,888	35.3%	
GS Mass Market	66,569	8,839	39.6%	132,777
GS Top Consumers	31	5,461	24.4%	179,045,566
GS Diesel	179	5	0.0%	29,141
GS Seasonal	861	5	0.0%	6,112
GS Flat Rate Water Heat	392	7	0.0%	18,165
GS Surplus Energy Program	28	29	0.1%	1,044,126
Total General Service	67,668	14,347	64.2%	
Sentinal Flat Rate	20,399	12	0.1%	568
Sentinal Rental	25,764	-	0.0%	-
Street Lighting	1,157	92	0.4%	79,571
Total Lighting	1,157	104	0.5%	
Total General Consumer Sales	552,438	22,338	100.0%	
Less Diesel Sales		(14)	-0.1%	
Distribution Losses		1,205	5.4%	
Construction Power		12	0.1%	
Manitoba Load at Common Bus		23,541	105.4%	
Transmission Losses		1,969	8.8%	
Less Non-Firm Energy		(29)	-0.1%	
Station Service		144	0.6%	
Gross Firm Energy		25,625	114.7%	

* flat rate and rental services are shown in yellow, which do not count as customers

FORECAST OVERVIEW

General Consumers Customer Forecast

In 2013/14, Manitoba Hydro had an average of 552,438 General Consumer Sales customers. These were made up of 462,274 Residential Basic customers, 66,569 General Service Mass Market customers, 31 General Service Top Consumers customers and 28 SEP (Surplus Energy Program, i.e. non-firm) customers, with the rest being Diesel, Seasonal and Area and Roadway Lighting.

During the last 10 years, Residential Basic customers have grown at an average of 4,558 (1.0%) per year. Manitoba Hydro's 2014 Economic Outlook provides the forecast of Residential Basic customers, and this document uses that forecast. It calls for a growth of 5,906 (1.2%) per year over the next ten years and 5,069 (1.0%) per year over the next 20 years. The primary reason for the increase is an expectation of increased population growth in Manitoba due to government immigration initiatives which will impact both the Residential and Commercial Sectors.

General Service Mass Market customers have grown 590 (0.9%) per year over the last 10 years. They are forecast to grow 546 (0.8%) over the next ten years and 446 (0.6%) over the next 20 years.

Residential Seasonal customers, who are mainly cottages with lower usage, are growing at a slower rate than Residential Basic, averaging 70 (0.3%) customers per year over the last 10 years. They are forecast to grow at 96 (0.5%) over the next 10 years and 98 (0.5%) over the next 20 years.

Area and Roadway Lighting customers were re-grouped in 2006 when Manitoba Hydro changed its billing system, and the lighting customer counts changed at that time. Area and Roadway Lighting is expected to grow at 5 (0.4%) customers annually over the next 10 years and 5 (0.4%) over the next 20 years.

Table 4 - General Consumers Sales Customers

GENERAL CONSUMERS SALES (Average Customers)
History and Forecast
2003/04 - 2033/34

Fiscal	Residential			General Service					Lighting	Total
Year	Basic	Diesel	Seas	Mass Mkt	Top Cons	Diesel	Seas	SEP		Custs
2003/04	416,690	500	20,056	60,672	27	151	788	33	757	499,674
2004/05	420,135	508	20,075	60,924	26	160	793	31	759	503,409
2005/06	423,742	519	20,145	61,491	26	168	814	29	793	507,727
2006/07	427,886	525	20,312	63,596	26	169	783	28	1129	514,455
2007/08	432,144	531	20,437	63,855	26	175	798	27	1142	519,135
2008/09	437,263	540	20,648	64,140	26	178	818	24	1175	524,811
2009/10	441,710	539	20,839	64,758	26	177	830	24	1191	530,095
2010/11	445,882	550	20,950	65,193	26	176	842	24	1184	534,828
2011/12	450,748	568	20,844	65,546	32	174	847	26	1155	539,939
2012/13	456,130	577	20,731	65,974	31	175	850	28	1164	545,660
2013/14	462,274	583	20,757	66,569	31	179	861	28	1157	552,438
10 Year	4,558	8	70	590	0	3	7	-1	40	5,276
Avg Gr.	1.0%	1.5%	0.3%	0.9%	1.3%	1.7%	0.9%	-1.6%	4.3%	1.0%
2014/15	468,076	587	20,814	67,125	31	180	871	28	1,160	558,871
2015/16	473,761	595	20,914	67,670	31	182	876	28	1,165	565,222
2016/17	479,963	603	21,014	68,267	31	184	881	32	1,170	572,144
2017/18	486,387	611	21,114	68,902	32	185	886	32	1,175	579,324
2018/19	492,700	619	21,214	69,530	32	187	891	32	1,180	586,385
2019/20	498,887	627	21,314	70,119	32	189	896	32	1,185	593,280
2020/21	504,914	635	21,414	70,655	32	191	901	32	1,190	599,963
2021/22	510,687	643	21,514	71,144	32	192	906	32	1,195	606,345
2022/23	516,160	652	21,614	71,599	32	194	911	32	1,200	612,393
2023/24	521,337	660	21,714	72,029	32	196	916	32	1,205	618,119
10 Year	5,906	8	96	546	0	2	5	0	5	6,568
Avg Gr.	1.2%	1.3%	0.5%	0.8%	0.5%	0.9%	0.6%	1.3%	0.4%	1.1%
2024/25	526,282	668	21,814	72,438	32	197	921	32	1,210	623,594
2025/26	531,016	676	21,914	72,828	32	199	926	32	1,215	628,837
2026/27	535,517	684	22,014	73,197	32	201	931	32	1,220	633,827
2027/28	539,802	692	22,114	73,547	32	202	936	32	1,225	638,582
2028/29	543,914	700	22,214	73,884	32	204	941	32	1,230	643,150
2029/30	547,924	708	22,314	74,210	32	206	946	32	1,235	647,607
2030/31	551,878	716	22,414	74,532	32	208	951	32	1,240	652,001
2031/32	555,807	724	22,514	74,850	32	209	956	32	1,245	656,370
2032/33	559,731	732	22,614	75,168	32	211	961	32	1,250	660,731
2033/34	563,659	740	22,714	75,485	32	213	966	32	1,255	665,095
20 Year	5,069	8	98	446	0	2	5	0	5	5,633
Avg Gr.	1.0%	1.2%	0.5%	0.6%	0.2%	0.9%	0.6%	0.7%	0.4%	0.9%

General Consumers Sales Forecast

During 2013/14, Total General Consumer Sales was 22,338 GW.h. The fiscal billing year (using weather from March 16, 2013 to March 15, 2014) was much colder than normal giving a weather adjustment for the year of -772 GW.h, resulting in a weather adjusted Total Sales value of 21,566 GW.h.

Over the last 10 years, Total Sales have grown at 228 GW.h (1.1%) per year. The growth was 1.6% per year in Residential Basic, 1.4% per year in General Service Mass Market, but only 0.1% in General Service Top Consumers due to the economic downturn in 2009 that included the loss of one Top Consumer customer. This historical growth includes the effect of past Demand Side Management (DSM) initiatives.

Sales are forecast to grow at 444 GW.h (1.9%) per year over the next 10 years and 378 GW.h (1.5%) per year over the next 20 years before accounting for future market-based DSM programs.

Most of the growth is forecast to occur in General Service Mass Market, growing 142 GW.h (1.4%) per year over the next twenty years, followed by Top Consumers at 132 GW.h (2.0%) per year and Residential Basic at 102 GW.h (1.2%) per year.

Table 5 - General Consumers Sales Energy

GENERAL CONSUMERS SALES (GW.h)
History and Forecast
2003/04 - 2033/34

Fiscal	Residential				General Service						Lighting	Total
Year	Basic	Diesel	Seas	FRWH	Mass Mkt	Top Cons	Diesel	Seas	FRWH	SEP		Sales
2003/04	6,170	6	56	34	7,460	5,423	5	5	13	17	91	19,280
2004/05	6,275	7	58	31	7,516	5,714	5	5	10	25	91	19,735
2005/06	6,171	7	59	30	7,587	5,948	5	5	9	23	91	19,935
2006/07	6,443	7	60	29	7,839	5,989	5	4	9	23	101	20,510
2007/08	6,736	7	68	27	8,006	6,075	5	4	9	24	101	21,061
2008/09	6,847	7	74	25	8,049	6,065	5	5	8	22	102	21,210
2009/10	6,786	7	81	24	7,985	5,461	6	5	8	20	102	20,486
2010/11	6,952	8	77	23	8,258	5,324	5	5	8	24	103	20,786
2011/12	6,818	8	83	22	8,162	5,531	5	5	8	25	103	20,771
2012/13	7,223	8	81	21	8,434	5,560	5	5	7	28	103	21,477
2013/14	7,767	9	92	20	8,839	5,461	5	5	7	29	104	22,338
Weather Adj.	-518	0	0	0	-252	0	0	0	0	-3	0	-772
2013/14 Wadj	7,249	9	92	20	8,587	5,461	5	5	7	26	104	21,566
10 Year Wadj	106	0	4	-1	114	4	0	0	-1	1	1	228
Avg Gr.	1.6%	3.4%	5.1%	-5.2%	1.4%	0.1%	1.4%	1.2%	-6.1%	4.0%	1.3%	1.1%
2014/15	7,380	9	91	19	8,814	6,003	6	5	7	29	104	22,467
2015/16	7,481	9	93	18	8,993	6,147	6	5	6	29	105	22,891
2016/17	7,606	9	95	17	9,190	6,082	6	5	6	32	105	23,153
2017/18	7,726	9	96	16	9,388	6,430	6	5	6	33	106	23,822
2018/19	7,836	10	98	15	9,560	6,590	6	5	6	33	106	24,264
2019/20	7,946	10	100	14	9,705	6,859	6	5	5	33	107	24,791
2020/21	8,049	10	102	14	9,833	6,922	6	5	5	33	107	25,087
2021/22	8,151	10	104	13	9,958	7,006	6	6	5	33	108	25,399
2022/23	8,248	10	106	12	10,079	7,091	6	6	5	33	108	25,704
2023/24	8,342	11	108	12	10,199	7,177	6	6	4	33	109	26,006
10 Year	109	0	2	-1	161	172	0	0	0	1	1	444
Avg Gr.	1.4%	2.1%	1.5%	-5.0%	1.7%	2.8%	1.5%	0.6%	-5.0%	2.2%	0.5%	1.9%
2024/25	8,435	11	110	11	10,320	7,264	6	6	4	33	109	26,309
2025/26	8,527	11	111	11	10,442	7,353	6	6	4	33	110	26,613
2026/27	8,619	11	113	10	10,560	7,443	6	6	4	33	110	26,916
2027/28	8,711	11	115	10	10,681	7,534	6	6	3	33	111	27,221
2028/29	8,802	12	117	9	10,801	7,626	6	6	3	33	111	27,527
2029/30	8,895	12	119	9	10,922	7,719	6	6	3	33	112	27,836
2030/31	8,990	12	121	8	11,046	7,813	6	6	3	33	112	28,151
2031/32	9,087	12	123	8	11,172	7,908	7	6	3	33	113	28,471
2032/33	9,186	13	125	7	11,301	8,005	7	6	3	33	113	28,799
2033/34	9,289	13	127	7	11,433	8,103	7	6	3	33	114	29,134
20 Year	102	0	2	-1	142	132	0	0	0	0	1	378
Avg Gr.	1.2%	2.0%	1.6%	-5.0%	1.4%	2.0%	1.2%	0.5%	-5.0%	1.1%	0.5%	1.5%

Manitoba Energy Forecast

The actual Gross Firm Energy was 25,625 GW.h in 2013/14. Gross Firm Energy has grown 269 GW.h (1.2%) per year for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. Gross Firm energy is forecast to grow to 33,177 GW.h by 2033/34 at an average growth of 425 GW.h or 1.5% per year. This is before accounting for future market-based DSM programs.

Distribution losses, which is the difference between Manitoba Hydro's substations and the customers' meters, has a wide variance from year to year and has ranged between 3.5% and 5.5% of Total Sales. It is forecast to be 4.4% of Sales for the entire forecast.

Transmission Losses which is the difference between the generators and the substations is forecast to be 9.2% of Total Sales for the entire forecast.

Distribution Losses and Transmission Losses total almost 14% which needs to be added to Total Sales to estimate Gross Firm Energy. This 14% value should generally be used to estimate load at generation when only load at the customer's meter is known, for example to convert Power Smart program savings from the customer meter to generation. The exception is for large General Service customers who own their own transformation and incur minimal Distribution Losses. For these customers, a 10% value should be used.

Table 6 - Components of Manitoba Energy

MANITOBA FIRM ENERGY (GW.h)
History and Forecast
2003/04 - 2033/34

Fiscal Year	General Consumer Sales less Diesel	Dist. Losses	Dist. Loss %	Const. Power	Manitoba Load at Common Bus	Trans. Losses	Trans. Loss %	Less Non Firm Energy	Station Service	Gross Firm Energy
2003/04	19,269	804	4.2%	43	20,116	1,792	9.3%	17	179	22,069
2004/05	19,724	830	4.2%	46	20,600	1,852	9.4%	26	163	22,589
2005/06	19,923	797	4.0%	42	20,761	1,860	9.3%	23	158	22,757
2006/07	20,497	900	4.4%	45	21,442	1,885	9.2%	22	159	23,464
2007/08	21,049	940	4.5%	47	22,036	1,949	9.3%	24	161	24,122
2008/09	21,198	1,052	5.0%	56	22,305	1,979	9.3%	22	154	24,417
2009/10	20,473	813	4.0%	75	21,361	1,934	9.4%	20	137	23,412
2010/11	20,773	947	4.6%	85	21,806	1,977	9.5%	25	134	23,892
2011/12	20,757	736	3.5%	67	21,560	1,939	9.3%	25	131	23,605
2012/13	21,463	1,184	5.5%	59	22,706	1,936	9.0%	28	136	24,750
2013/14	22,324	1,205	5.4%	12	23,541	1,969	8.8%	29	144	25,625
Weather Adj.	-772	-109		0	-881	-70		-3	0	-948
2013/14 Wadj	21,552	1,096	5.1%	12	22,660	1,899	8.8%	26	144	24,677
10 Year Wadj	227	24		-3	262	14		1	-4	269
Avg Gr.	1.1%	2.5%		-11.7%	1.2%	0.8%		4.3%	-2.2%	1.2%
2014/15	22,452	988	4.4%	24	23,464	2,067	9.2%	29	137	25,639
2015/16	22,876	1,007	4.4%	33	23,915	2,106	9.2%	29	137	26,130
2016/17	23,138	1,018	4.4%	43	24,200	2,131	9.2%	32	137	26,436
2017/18	23,807	1,047	4.4%	25	24,879	2,191	9.2%	33	137	27,174
2018/19	24,249	1,067	4.4%	12	25,328	2,231	9.2%	33	137	27,662
2019/20	24,775	1,090	4.4%	0	25,865	2,278	9.2%	33	137	28,247
2020/21	25,071	1,103	4.4%	0	26,174	2,305	9.2%	33	137	28,583
2021/22	25,383	1,117	4.4%	0	26,499	2,334	9.2%	33	137	28,937
2022/23	25,688	1,130	4.4%	0	26,818	2,362	9.2%	33	137	29,284
2023/24	25,989	1,144	4.4%	0	27,133	2,390	9.2%	33	137	29,626
10 Year	444	5		-1	447	49		1	-1	495
Avg Gr.	1.9%	0.4%		-100.0%	1.8%	2.3%		2.3%	-0.5%	1.8%
2024/25	26,292	1,157	4.4%	0	27,449	2,418	9.2%	33	137	29,970
2025/26	26,596	1,170	4.4%	0	27,766	2,446	9.2%	33	137	30,316
2026/27	26,898	1,184	4.4%	0	28,082	2,473	9.2%	33	137	30,659
2027/28	27,204	1,197	4.4%	0	28,401	2,501	9.2%	33	137	31,006
2028/29	27,509	1,210	4.4%	0	28,719	2,529	9.2%	33	137	31,352
2029/30	27,818	1,224	4.4%	0	29,042	2,558	9.2%	33	137	31,703
2030/31	28,133	1,238	4.4%	0	29,370	2,587	9.2%	33	137	32,061
2031/32	28,452	1,252	4.4%	0	29,704	2,616	9.2%	33	137	32,424
2032/33	28,780	1,266	4.4%	0	30,046	2,646	9.2%	33	137	32,796
2033/34	29,115	1,281	4.4%	0	30,396	2,677	9.2%	33	137	33,177
20 Year	378	9		-1	387	39		0	0	425
Avg Gr.	1.5%	0.8%		-100.0%	1.5%	1.7%		1.1%	-0.2%	1.5%

Comparison of the 2013 Forecast to Actuals

Comparison of the 2013 Forecast to the 2013/14 Weather Adjusted Actuals

The weather adjusted General Consumer Sales for 2013/14 was 21,566 GW.h which was 510 GW.h lower than the 2013 forecast of 22,076 GW.h.

The weather adjusted Residential Basic sector was 90 GW.h lower than the forecast and the weather adjusted General Service Mass Market sector for was 37 GW.h higher than forecast. These differences do not take into account Demand Side Management (DSM) programs that were forecast to be 25 GW.h for Residential Basic and 56 GW.h for General Service Mass Market. With DSM incorporated, Residential Basic was 65 GW.h lower than forecast and General Service Mass Market was 93 GW.h higher than forecast.

The majority of the difference was in the Top Consumers sector for 2013/14 using 5,461 GW.h that was 464 GW.h lower than the 2013 forecast of 5,925 GW.h. Three Top Consumers contributed to the majority of this difference. Two had unexpected reductions of load in 2013/14 that are expected to be mostly restored in 2014/15. The third had a delay to a current expansion project but the forecast load is still expected and is included in the 2014 Forecast.

Distribution losses were 125 GW.h higher than forecast and Transmission losses were 159 GW.h lower than forecast.

Overall, the weather adjusted Gross Firm Energy for 2013/14 was 24,677 GW.h which was 562 GW.h lower than the 2013 forecast of 25,239 GW.h.

The normalized Gross Total Peak for 2013/14 was 4,587 MW, 28 MW higher than forecast.

Table 7 - 2013/14 Forecast to Actual

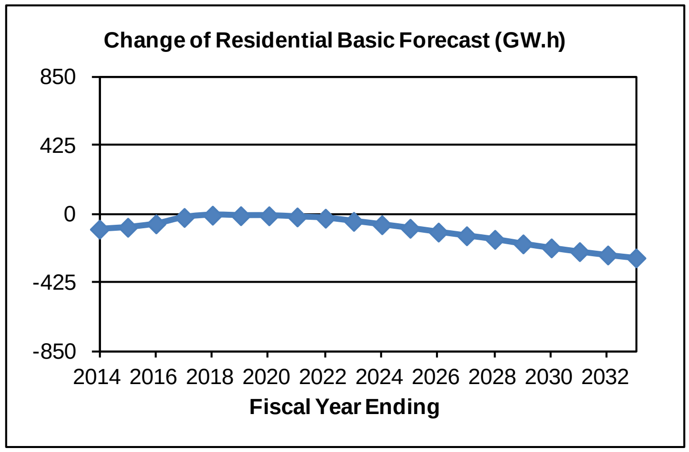
2013 FORECAST COMPARED TO WEATHER ADJUSTED ACTUALS 2013/14 Energy (GW.h) and Peak (MW)					
Forecast Group	Actuals	Weather Adjustment	Wthr Adj Actuals	2013 Forecast	WA Actuals less Forecast
Residential Basic	7,767	(518)	7,249	7,339	(90)
Residential Diesel	9	-	9	8	0
Residential Seasonal	92	-	92	83	10
Residential Flat Rate Water Heating	20	-	20	20	(0)
Total Residential	7,888	(518)	7,370	7,450	(80)
GS Mass Market	8,839	(252)	8,587	8,550	37
GS Top Consumers	5,461	-	5,461	5,925	(464)
GS Diesel	5	-	5	5	(0)
GS Seasonal	5	-	5	5	0
GS Flat Rate Water Heat	7	-	7	7	0
GS Surplus Energy Program	29	(3)	26	30	(3)
Total General Service	14,347	(255)	14,092	14,522	(430)
Sentinal Flat Rate	12	-	12	12	(0)
Sentinal Rental	-	-	-	-	-
Street Lighting	92	-	92	92	(0)
Total Lighting	104	-	104	104	(0)
Total General Consumer Sales	22,338	(772)	21,566	22,076	(510)
Less Diesel Sales	(14)	-	(14)	(14)	0
Distribution Losses	1,205	(109)	1,096	971	125
Construction Power	12	-	12	43	(30)
Manitoba Load at Common Bus	23,541	(881)	22,660	23,076	(415)
Transmission Losses	1,969	(70)	1,899	2,058	(159)
Less Non-Firm Energy	(29)	3	(26)	(30)	3
Station Service	144	-	144	134	9
Gross Firm Energy (GW.h)	25,625	(948)	24,677	25,239	(562)
Gross Total Peak (MW)	4,743	(155)	4,587	4,559	28

*Note: Actuals include DSM. Forecast excludes program-based DSM initiatives.

Change between the 2013 and 2014 Forecasts

Change Between the 2013 and 2014 Residential Basic Forecast

Figure 1 - Change of Res Basic Forecast



The 2014 Residential Basic Forecast starts down 78 GW.h from the 2013 forecast. By 2017/18, it is only down 3 GW.h due to a higher customer forecast in the earlier years. The difference then grows to be 268 GW.h down due to a lower customer forecast for the later years. 268 GW.h represents less than 1 year of Manitoba system load growth (1 year = approximately 425 GW.h).

Major changes and their 2032/33 effect:

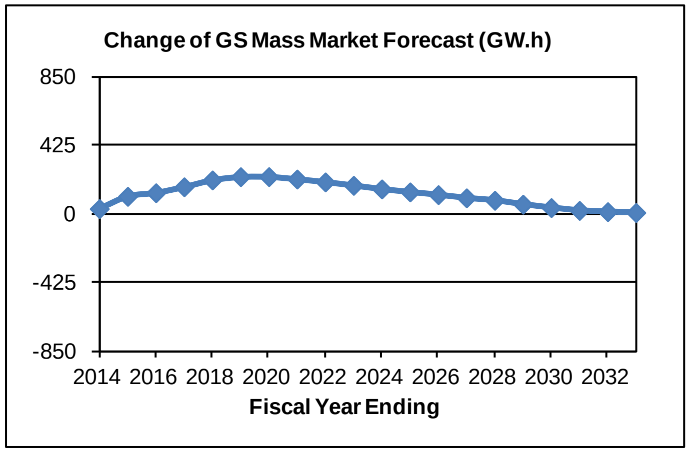
1. The customer forecast was lowered by 4,854 (-80 GW.h).
2. Estimates of the reduction due to future Codes & Standards was increased (-384 GW.h).
3. Change to average use due to implementation of econometric model (+200 GW.h), from:
   a. Historical growth excluding evaluated DSM and Codes & Standards: +447 GW.h
   b. Increase due to the modeling of real Income: +628 GW.h
   c. Decrease due to the modeling of real electricity price: -875 GW.h
4. Modeling of ratio of gas to electric price on new home saturations (-33 GW.h)

Table 8 - Change of Res Basic Forecast

CHANGE OF RESIDENTIAL BASIC FORECAST (GW.h) Comparison of 2013 to 2014 forecast									
Fiscal Year	2013 Fcst	2014 Fcst	Change	%	Fiscal Year	2013 Fcst	2014 Fcst	Change	%
2013/14	7,339	7,249	(90)	-1.2%	2023/24	8,405	8,342	(62)	-0.7%
2014/15	7,458	7,380	(78)	-1.0%	2024/25	8,520	8,435	(85)	-1.0%
2015/16	7,538	7,481	(57)	-0.8%	2025/26	8,635	8,527	(108)	-1.3%
2016/17	7,624	7,606	(17)	-0.2%	2026/27	8,750	8,619	(131)	-1.5%
2017/18	7,730	7,726	(3)	0.0%	2027/28	8,864	8,711	(153)	-1.7%
2018/19	7,842	7,836	(7)	-0.1%	2028/29	8,983	8,802	(181)	-2.0%
2019/20	7,953	7,946	(7)	-0.1%	2029/30	9,102	8,895	(206)	-2.3%
2020/21	8,063	8,049	(14)	-0.2%	2030/31	9,219	8,990	(229)	-2.5%
2021/22	8,173	8,151	(22)	-0.3%	2031/32	9,337	9,087	(250)	-2.7%
2022/23	8,290	8,248	(42)	-0.5%	2032/33	9,454	9,186	(268)	-2.8%

Change Between the 2013 and 2014 GS Mass Market Forecast

Figure 2 - Change of GS Mass Market Forecast



The 2014 General Service Mass Market Forecast is up 235 GW.h in 2018/19 from the 2013 forecast primarily due to the increase in the short term Residential customer forecast. By 2032/33, the Mass Market forecast is only up 13 GW.h by 2032/33.

Major changes and their 2032/33 effect:

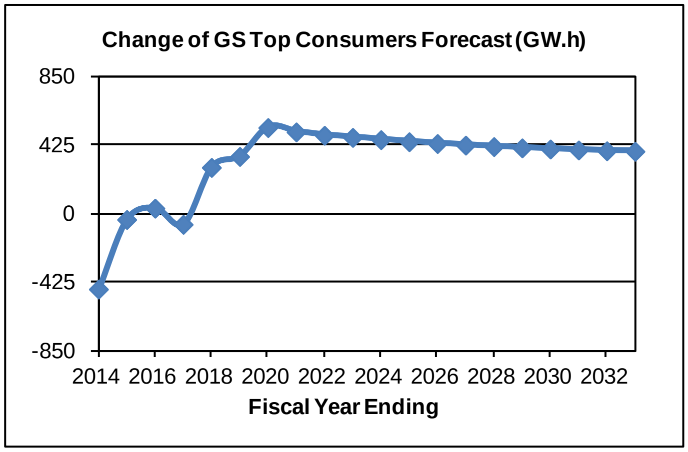
1. The forecast of GS Mass Market customers was lowered by 1,046 due to a lower GDP forecast and a lower Residential Customer forecast (-138 GW.h).
2. Estimates of the reduction due to future Codes and Standards was increased (-517 GW.h)
3. Change to average use due to implementation of econometric model (+637 GW.h), from:
   a. Growth of historical average use due to adding DSM and Codes & Standards: +423 GW.h
   b. Increase due to the modeling of real GDP: +997 GW.h
   c. Decrease due to the modeling of real electricity price: -783 GW.h

Table 9 **- Change of GS Mass Market Forecast**

CHANGE OF GS MASS MARKET FORECAST (GW.h) Comparison of 2013 to 2014 forecast										
Fiscal Year	2013 Fcst	2014 Fcst	Change	%		Fiscal Year	2013 Fcst	2014 Fcst	Change	%
2013/14	8,550	8,587	37	0.4%		2023/24	10,040	10,199	159	1.6%
2014/15	8,701	8,814	113	1.3%		2024/25	10,179	10,320	141	1.4%
2015/16	8,858	8,993	135	1.5%		2025/26	10,318	10,442	123	1.2%
2016/17	9,018	9,190	172	1.9%		2026/27	10,456	10,560	104	1.0%
2017/18	9,174	9,388	215	2.3%		2027/28	10,592	10,681	89	0.8%
2018/19	9,325	9,560	235	2.5%		2028/29	10,736	10,801	64	0.6%
2019/20	9,470	9,705	235	2.5%		2029/30	10,878	10,922	43	0.4%
2020/21	9,613	9,833	220	2.3%		2030/31	11,020	11,046	26	0.2%
2021/22	9,756	9,958	202	2.1%		2031/32	11,154	11,172	18	0.2%
2022/23	9,898	10,079	181	1.8%		2032/33	11,288	11,301	13	0.1%

Change Between the 2013 and 2014 GS Top Consumers Forecast

Figure 3 - Change of GS Top Consumer Forecast



The General Service Top Consumers is similar to the 2013 forecast for the first three years, and then rises to be 537 GW.h higher in 2019/20 primarily due to pipeline projects. From 2020/21, the change slowly decreases due to a reduction to the annual amount allocated to the Potential Large Industrial Loads. By 2032/33, the increase is 390 GW.h. This is less than a year of Manitoba system load growth (1 year = approximately 425 GW.h).

Changes made (and the 2032/33 effect):

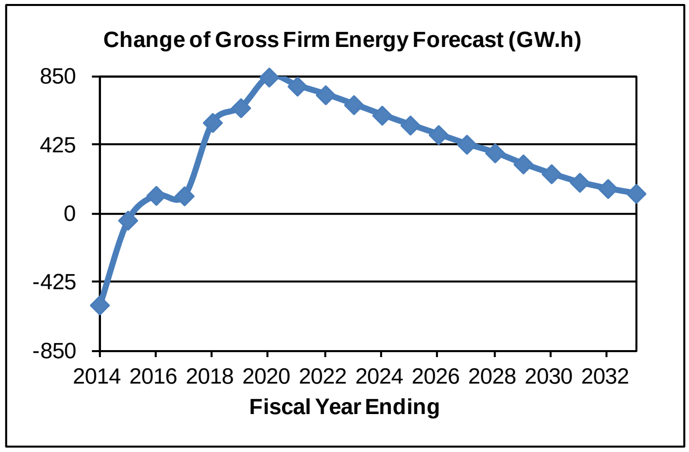
1. Load was down 464 GW.h in 2013/14 due to a temporary equipment problem with one top consumer and an unexpected reduction of a second top consumer. (-50 GW.h)
2. Two major expansion projects are expected in the Pipeline sector. (+655 GW.h)
3. The Potential Large Industrial Loads forecast was reduced from an average 100 GW.h per year to 91 GW.h per year. (-159 GW.h)
4. Potential Large Industrial Loads begins in the 4th year of the forecast, which in the 2014 forecast is one year later giving one less year of PLIL growth by 2032/33. (-98 GW.h)

Table 10 - Change of GS Top Consumer Forecast

CHANGE OF GS TOP CONSUMERS FORECAST (GW.h) Comparison of 2013 to 2014 forecast										
Fiscal Year	2013 Fcst	2014 Fcst	Change	%		Fiscal Year	2013 Fcst	2014 Fcst	Change	%
2013/14	5,925	5,461	(464)	-7.8%		2023/24	6,715	7,177	462	6.9%
2014/15	6,036	6,003	(33)	-0.5%		2024/25	6,815	7,264	449	6.6%
2015/16	6,110	6,147	37	0.6%		2025/26	6,915	7,353	438	6.3%
2016/17	6,145	6,082	(63)	-1.0%		2026/27	7,015	7,443	428	6.1%
2017/18	6,140	6,430	290	4.7%		2027/28	7,115	7,534	419	5.9%
2018/19	6,232	6,590	358	5.7%		2028/29	7,215	7,626	411	5.7%
2019/20	6,322	6,859	537	8.5%		2029/30	7,315	7,719	404	5.5%
2020/21	6,412	6,922	510	8.0%		2030/31	7,415	7,813	398	5.4%
2021/22	6,517	7,006	489	7.5%		2031/32	7,515	7,908	393	5.2%
2022/23	6,615	7,091	476	7.2%		2032/33	7,615	8,005	390	5.1%

Change Between the 2013 and 2014 Gross Firm Energy Forecast

Figure 4 - Change of Energy Forecast



The Gross Firm Energy forecast was down 562 GW.h in 2013/14 due to a temporary load loss of two Top Consumers. By 2019/20, the 2014 forecast is 850 GW.h higher due to increases to Top Consumers in the Pipeline sector and a higher Residential customer forecast in the earlier years. By 2032/33 the increase in the 2014 forecast is reduced to 129 GW.h due to a reduction in the Residential customer forecast and increases to the projected impacts of Codes and Standards. This equates to a 0.4% increase in the forecast of 2032/33, which is a gain of less than half a year of load growth (1 year = approximately 425 GW.h).

Summary of changes made in each sector (and the 2032/33 effect):

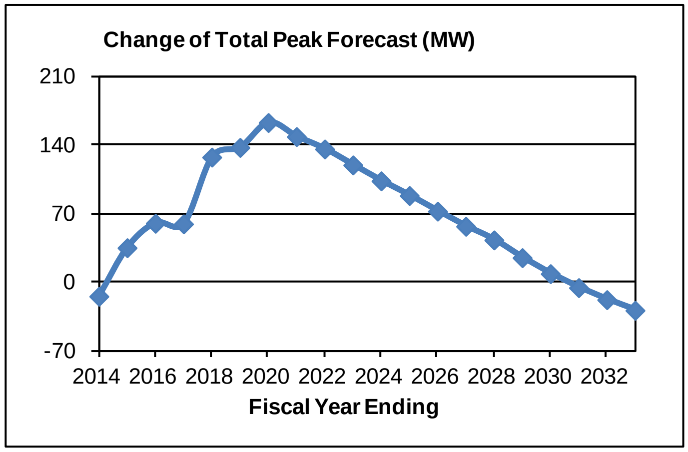
1. Residential Basic forecast, primarily due to an overall reduction in the Residential customer forecast and projected energy savings due to Codes and Standards. (-268 GW.h)
2. General Service Mass Market forecast, due to mostly offsetting changes. (+13 GW.h)
3. General Service Top Consumers forecast, mostly in the Pipelines sector. (+390 GW.h)
4. Other Sales and Losses. (-6 GW.h)

Table 11 - Change of Energy Forecast

GROSS FIRM ENERGY (GW.h) Comparison of 2013 to 2014 forecast										
Fiscal Year	2013 Fcst	2014 Fcst	Change	%		Fiscal Year	2013 Fcst	2014 Fcst	Change	%
2013/14	25,239	24,677	(562)	-2.2%		2023/24	29,013	29,626	614	2.1%
2014/15	25,676	25,639	(37)	-0.1%		2024/25	29,418	29,970	552	1.9%
2015/16	26,013	26,130	117	0.4%		2025/26	29,822	30,316	493	1.7%
2016/17	26,322	26,436	114	0.4%		2026/27	30,225	30,659	433	1.4%
2017/18	26,606	27,174	568	2.1%		2027/28	30,625	31,006	380	1.2%
2018/19	27,003	27,662	660	2.4%		2028/29	31,041	31,352	312	1.0%
2019/20	27,398	28,247	850	3.1%		2029/30	31,453	31,703	251	0.8%
2020/21	27,789	28,583	794	2.9%		2030/31	31,863	32,061	198	0.6%
2021/22	28,197	28,937	740	2.6%		2031/32	32,265	32,424	159	0.5%
2022/23	28,605	29,284	679	2.4%		2032/33	32,667	32,796	129	0.4%

Change Between the 2013 and 2014 Gross Total Peak Forecast

Figure 5 - Change of Peak Forecast



The Gross Total Peak forecast is down 28 MW (0.5%) by 2032/33 from the 2013 forecast. The peak forecast very closely follows the energy forecast with the reasons for reduction in peak being similar to those for energy.

In 2032/33 the peak forecast is lower than projected in the 2013 forecast because of a small increase of the expected peak load factor which is forecast to grow to 63.2% compared to 62.6% in the 2013 forecast. The Load Factor increase is due to the Top Consumers forecast growing at a faster rate than other sectors.

The reduction in peak in 2032/33 amounts to 28 MW, less than a half a year of load growth. (1 year = approximately 70 MW).

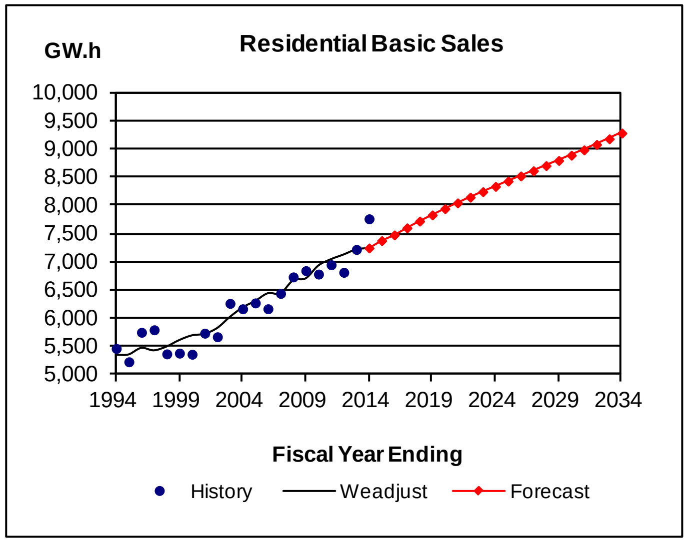
Table 12 - Change of Peak Forecast

GROSS TOTAL PEAK (MW) Comparison of 2013 to 2014 forecast									
Fiscal Year	2013 Fcst	2014 Fcst	Change	%	Fiscal Year	2013 Fcst	2014 Fcst	Change	%
2013/14	4,601	4,587	(14)	-0.3%	2023/24	5,296	5,400	104	2.0%
2014/15	4,680	4,716	36	0.8%	2024/25	5,369	5,458	89	1.7%
2015/16	4,742	4,803	61	1.3%	2025/26	5,443	5,516	73	1.3%
2016/17	4,801	4,861	60	1.3%	2026/27	5,516	5,574	58	1.0%
2017/18	4,857	4,985	128	2.6%	2027/28	5,588	5,632	44	0.8%
2018/19	4,930	5,068	138	2.8%	2028/29	5,664	5,690	26	0.5%
2019/20	5,002	5,166	164	3.3%	2029/30	5,739	5,748	9	0.2%
2020/21	5,074	5,223	149	2.9%	2030/31	5,813	5,808	(5)	-0.1%
2021/22	5,147	5,284	137	2.7%	2031/32	5,886	5,869	(17)	-0.3%
2022/23	5,222	5,342	120	2.3%	2032/33	5,959	5,931	(28)	-0.5%

FORECAST DETAILS

Residential Basic

Figure 6- Residential Basic Sales



In 2013/14, there were 462,274 Residential Basic customers. 79% are single detached, 9% multi attached, and 12% individually metered apartment suites. 54% are in Winnipeg where natural gas is available, 29% in natural gas available areas outside Winnipeg, and 17% do not have natural gas available.

Residential Basic has grown 100 GW.h (1.6%) per year for the past 20 years and 106 GW.h per year (1.6%) for the past 10 years which reflects the effect of past Demand Side Management (DSM) initiatives. It is forecast to grow 109 GW.h (1.4%) per year for the next 10 years and 102 GW.h (1.2%) per year for the next 20 years.

The primary drivers of Residential Basic growth are population and average use per customer. The population is forecast to grow 1.2% per year over the next 10 years and 1.0% over the next 20 years. The increase in average use per customer is expected to add 0.2% to the growth.

Table 13 - Residential Sales

RESIDENTIAL BASIC (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1994/95	5,230	119	5,348	2014/15	7,380
1995/96	5,753	-288	5,465	2015/16	7,481
1996/97	5,797	-375	5,422	2016/17	7,606
1997/98	5,370	120	5,490	2017/18	7,726
1998/99	5,384	221	5,605	2018/19	7,836
1999/00	5,364	325	5,689	2019/20	7,946
2000/01	5,737	-19	5,718	2020/21	8,049
2001/02	5,674	148	5,821	2021/22	8,151
2002/03	6,266	-247	6,019	2022/23	8,248
2003/04	6,170	18	6,188	2023/24	8,342
2004/05	6,275	30	6,305	2024/25	8,435
2005/06	6,171	272	6,442	2025/26	8,527
2006/07	6,443	-1	6,442	2026/27	8,619
2007/08	6,736	-62	6,674	2027/28	8,711
2008/09	6,847	-137	6,710	2028/29	8,802
2009/10	6,786	154	6,940	2029/30	8,895
2010/11	6,952	101	7,053	2030/31	8,990
2011/12	6,818	319	7,137	2031/32	9,087
2012/13	7,223	4	7,228	2032/33	9,186
2013/14	7,767	-518	7,249	2033/34	9,289

Table 14 - Residential Basic Sales

RESIDENTIAL BASIC SALES History and Forecast 2013/14 - 2033/34											
Fiscal	Electric Heat Billed			Non Electric Heat Billed			Total Basic			% Elec Space Heat	% Elec Water Heat
Year	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust		
2013/14	165,576	4,148	25,050	290,554	3,072	10,572	456,130	7,219	15,827	36.3%	49.0%
2014/15	173,561	4,324	24,913	294,514	3,056	10,377	468,075	7,380	15,767	37.1%	49.4%
2015/16	177,387	4,395	24,775	296,375	3,086	10,412	473,762	7,481	15,790	37.4%	50.5%
2016/17	181,184	4,474	24,693	298,780	3,132	10,484	479,964	7,606	15,848	37.7%	51.5%
2017/18	184,929	4,549	24,601	301,458	3,177	10,538	486,387	7,726	15,885	38.0%	52.3%
2018/19	188,478	4,618	24,501	304,222	3,218	10,577	492,700	7,836	15,904	38.3%	53.1%
2019/20	191,795	4,683	24,419	307,092	3,263	10,625	498,887	7,946	15,928	38.4%	53.8%
2020/21	194,868	4,743	24,341	310,046	3,306	10,663	504,914	8,049	15,942	38.6%	54.5%
2021/22	197,696	4,800	24,280	312,991	3,351	10,705	510,687	8,151	15,960	38.7%	55.1%
2022/23	200,277	4,853	24,230	315,883	3,396	10,749	516,160	8,248	15,980	38.8%	55.8%
2023/24	202,640	4,902	24,192	318,697	3,440	10,794	521,337	8,342	16,002	38.9%	56.4%
2024/25	204,859	4,951	24,167	321,424	3,485	10,842	526,283	8,435	16,028	38.9%	57.1%
2025/26	206,970	4,998	24,148	324,046	3,529	10,891	531,016	8,527	16,058	39.0%	57.7%
2026/27	208,970	5,044	24,140	326,547	3,575	10,947	535,517	8,619	16,095	39.0%	58.3%
2027/28	210,869	5,090	24,140	328,932	3,621	11,008	539,801	8,711	16,138	39.1%	59.0%
2028/29	212,686	5,135	24,145	331,228	3,667	11,071	543,914	8,802	16,183	39.1%	59.6%
2029/30	214,445	5,181	24,158	333,479	3,715	11,140	547,924	8,895	16,235	39.1%	60.2%
2030/31	216,165	5,226	24,176	335,713	3,764	11,212	551,878	8,990	16,290	39.2%	60.8%
2031/32	217,856	5,272	24,200	337,951	3,815	11,289	555,807	9,087	16,349	39.2%	61.4%
2032/33	219,528	5,319	24,228	340,203	3,868	11,369	559,731	9,186	16,412	39.2%	62.0%
2033/34	221,184	5,366	24,262	342,474	3,922	11,453	563,658	9,289	16,479	39.2%	62.6%

Electric Heat Billed: Customers who have electric space heating included with their electric bill.
Non Electric Heat Billed: Customers who do not have electric space heating included with their electric bill.
% Electric Space Heat: The proportion of Total Basic customers who are Electric Heat Billed.
% Electric Water Heat: The proportion of Total Basic customers who have Electric Water Heaters.

The average use (kW.h/customer) for Electric Heat Billed customers is decreasing as individually metered apartment suites are making up a higher proportion of the growth. The average use for Non Electric Heat Billed customers is increasing mainly due to the increase in the use of electric water heaters, the increase due to ventilation requirements in new dwellings, and miscellaneous end uses.

Residential Diesel, Seasonal, and Flat Rate Water Heating

Residential Diesel

There were 583 Residential Diesel customers that used 9 GW.h in 2013/14 at an average of 14,791 kW.h per customer. They have 60 amp service that does not allow for electric space heating. Space heating in these four communities is mainly provided by fuel oil. The number of customers is expected to grow to 740 and usage is expected to increase 2.0% a year to 13 GW.h by 2033/34 under the assumption that the communities continue to be separate from the Integrated System.

Residential Seasonal

There were 20,757 Residential Seasonal customers that used 92 GW.h in 2013/14 at an average of 4,455 kW.h per customer. The number of customers is expected increase to 22,714 customers by 2033/34. Seasonal customers are billed only twice a year either due to low usage (being a seasonal residence or cottage) or because of a location that makes it difficult to access for more frequent meter readings. The usage of Residential Seasonal customers is expected to increase 1.6% a year to 127 GW.h in 2033/34.

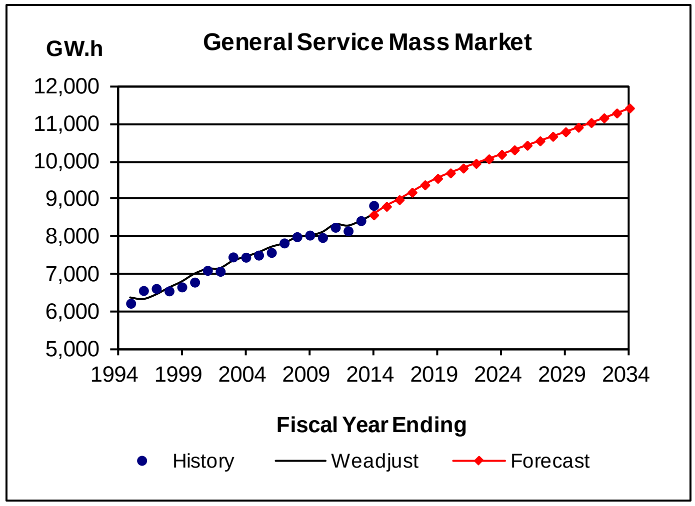
Residential Flat Rate Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 3,858 remaining services in 2013/14. The number of services and usage is expected to decrease 5% per year throughout the forecast period. Usage was 20 GW.h in 2013/14 and that will decrease to 7 GW.h by 2033/34.

General Service Mass Market

General Service Mass Market includes all Commercial and Industrial customers, excluding the General Service Top Consumers. There were 66,569 General Service Mass Market customers in 2013/14. Approximately 85% are Commercial and the others are Industrial.

Figure 7 - General Service Mass Market



GS Mass Market has grown 117 GW.h (1.6%) per year for the past 20 years and 114 GW.h per year (1.4%) for the past 10 years. This historical growth reflects the effect of past Demand Side Management (DSM) initiatives. It is forecast to grow 161 GW.h (1.7%) per year for the next 10 years and 142 GW.h (1.4%) per year for the next 20 years.

The primary driver for growth in the GS Mass Market is the number of Residential Basic customers. As population grows, commercial and industrial services grow to service the population. The secondary driver is the economy. Changes in the Manitoba Gross Domestic Product (GDP) are reflected in the GS Mass Market's electricity use.

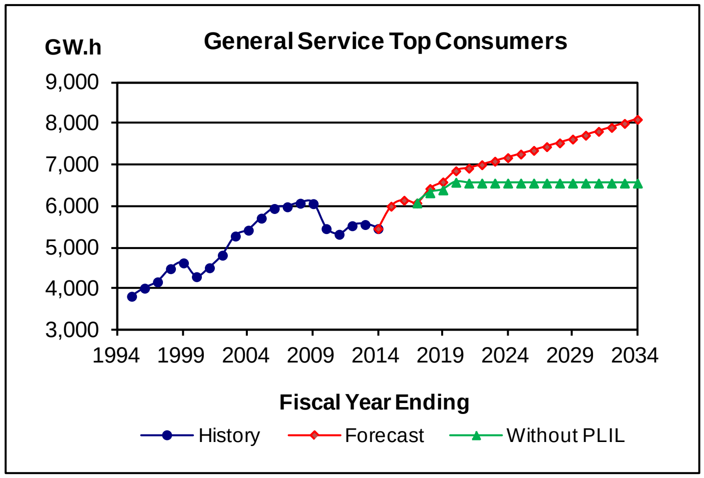
Table 15 - General Service Mass Market

GENERAL SERVICE MASS MARKET (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1994/95	6,233	131	6,364	2014/15	8,814
1995/96	6,573	-252	6,321	2015/16	8,993
1996/97	6,627	-185	6,442	2016/17	9,190
1997/98	6,562	62	6,624	2017/18	9,388
1998/99	6,668	118	6,786	2018/19	9,560
1999/00	6,796	197	6,993	2019/20	9,705
2000/01	7,110	15	7,125	2020/21	9,833
2001/02	7,084	60	7,144	2021/22	9,958
2002/03	7,467	-128	7,339	2022/23	10,079
2003/04	7,460	-8	7,452	2023/24	10,199
2004/05	7,516	49	7,565	2024/25	10,320
2005/06	7,587	125	7,712	2025/26	10,442
2006/07	7,839	-30	7,809	2026/27	10,560
2007/08	8,006	-38	7,968	2027/28	10,681
2008/09	8,049	-35	8,013	2028/29	10,801
2009/10	7,985	123	8,108	2029/30	10,922
2010/11	8,258	55	8,313	2030/31	11,046
2011/12	8,162	116	8,278	2031/32	11,172
2012/13	8,434	-27	8,407	2032/33	11,301
2013/14	8,839	-252	8,587	2033/34	11,433

General Service Top Consumers

General Service Top Consumers includes the top energy consuming businesses in Manitoba and represents 25% of all General Consumers Sales. GS Top Consumers includes 17 companies that account for 31 customers in the Primary Metals, Chemicals, Petrol/Oil/Natural Gas, Pulp/Paper, Food/Beverage and Colleges/Universities sectors.

Figure 8 - General Service Top Consumers



GS Top Consumers has grown 86 GW.h (1.9%) per year over the past 20 years and but only 4 GW.h per year (0.1%) over the past 10 years. The loss of one Top Consumer and the effect of the economic downturn from 2008 to 2011 lowered the past 10 year growth rate. The 2014 forecast is expected to grow 172 GW.h (2.8%) per year for the next 10 years and 132 GW.h (2.0%) per year for the next 20 years. The short term increase is primarily due to planned expansions in the Petrol/Oil/Natural Gas sector. In the long term, GS Top Consumers is expected to grow at a rate dependent on the Canada and U.S. Gross Domestic Product (GDP) projections.

Table 16 - General Service Top Consumers

GENERAL SERVICE TOP CONSUMERS (GW.h) HISTORICAL/FORECAST WITH PLIL					
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total
1994/95	3,825	2014/15	6,003	0	6,003
1995/96	4,021	2015/16	6,147	0	6,147
1996/97	4,173	2016/17	6,082	0	6,082
1997/98	4,493	2017/18	6,327	103	6,430
1998/99	4,632	2018/19	6,397	193	6,590
1999/00	4,299	2019/20	6,582	277	6,859
2000/01	4,515	2020/21	6,562	360	6,922
2001/02	4,818	2021/22	6,562	444	7,006
2002/03	5,282	2022/23	6,562	529	7,091
2003/04	5,423	2023/24	6,562	615	7,177
2004/05	5,714	2024/25	6,562	702	7,264
2005/06	5,948	2025/26	6,562	791	7,353
2006/07	5,989	2026/27	6,562	881	7,443
2007/08	6,075	2027/28	6,562	972	7,534
2008/09	6,065	2028/29	6,562	1,064	7,626
2009/10	5,461	2029/30	6,562	1,157	7,719
2010/11	5,324	2030/31	6,562	1,251	7,813
2011/12	5,531	2031/32	6,562	1,346	7,908
2012/13	5,560	2032/33	6,562	1,443	8,005
2013/14	5,461	2033/34	6,562	1,541	8,103

GS Top Consumers are forecast individually as their usage does not grow in a slow, steady, predictable pattern. Their short term outlooks are not conducive to econometric forecasting models and must be examined on an individual basis. The forecast for each company includes their short term committed plans and expectations over the next several years, but excludes longer term plans that are uncommitted and subject to change.

The sum of the individual company forecasts grow from 5,461 GW.h in 2013/14 to 6,582 GW.h by 2019/20. This growth of 1,121 GW.h includes the load changes due to committed plans of companies, and also includes an expected major load decrease of one customer by 2016.

Top Consumers do not add small amounts of load on a regular interval basis. Instead, they make major changes that add or remove a large amount of load at one time. Load changes are related to individual business cycles and it may be years between one of these changes.

For the longer term, an average expected growth is included for all customers together. This added growth is called Potential Large Industrial Loads (PLIL). It includes consideration for company expansions, cutbacks and shutdowns, new startups of 100 GW.h a year or more, and the long term normal incremental growth of all the companies within the Top Consumers sector combined. Since customer intentions are generally known for the first three years, PLIL is not added until 2017/18, the fourth year of the forecast.

GS Top Consumers has grown an average of 86 GW.h (1.9%) per year over the past twenty years. During that time, there were four new customers totaling 1,100 GW.h, nine instances of major customer expansions totaling 1,400 GW.h, and two existing customers who closed operations reducing consumption by 700 GW.h. None of these events could have been predicted five years before they occurred. One new customer and four expansions occurred within the past 10 years despite the economic downturn. These major events amount to a net 1,800 GW.h increase or 90 GW.h annually over the past 20 years. PLIL is estimated econometrically and averages 91 GW.h (1.3%) per year starting in the fourth year of the forecast and will total 1,541 GW.h by 2033/34.

1,541 GW.h is approximately equivalent to the load of Manitoba Hydro's largest consumer. If only one other customer of similar size starts up in Manitoba within the next 20 years, this one new customer alone would consume all of the provision that PLIL has projected.

General Service Diesel, Seasonal, and Flat Rate Water Heat

General Service Diesel

In 2013/14, there were 179 General Service Diesel Full Cost customers. They used 5 GW.h in 2013/14. The group is forecast to use 7 GW.h by 2033/34.

General Service Seasonal

There were 861 General Service Seasonal customers in 2013/14. Consumption was 5 GW.h in 2013/14 and is expected to grow to 6 GW.h by 2033/34.

General Service Flat Rate Water Heating

General Service Water Heating is a flat rate unmetered service that has not been available to new customers since November 12, 1969. There were 392 remaining services in 2013/14. The number of services is expected to decrease 5% per year throughout the forecast period. Consumption was 7 GW.h in 2013/14 and that is forecast to decrease to 3 GW.h by 2033/34.

General Service Surplus Energy Program

Participants in the Surplus Energy Program (SEP) used 29 GW.h in 2013/14 and are expected to grow to use 33 GW.h per year by 2017/18 and continue at that rate for the remainder of the forecast. This energy is considered to be “interruptible” and thus “non-firm”. The energy used by these customers is included in Sales. But it is excluded from the Gross Firm Energy forecast.

Plug-In Electric Vehicles

This forecast includes an estimate of the future adoption of Plug-In Electric Vehicles (PEVs) in the Manitoba Hydro service area. This is made up of two types:

(1) Plug-In Hybrid Electric Vehicles (PHEVs) that run on an electric battery but use an internal combustion engine (ICE) when the electricity runs low. An example is the Chevrolet Volt.

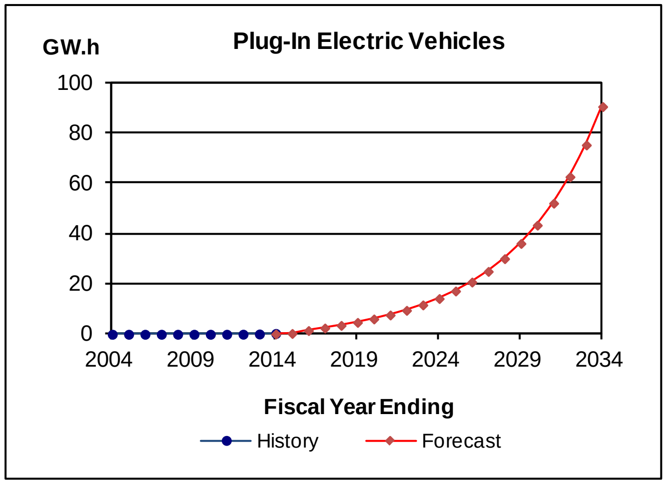
(2) Battery Electric Vehicles (BEVs) run only on electric battery power. Pure electric plug-in vehicles include the Nissan Leaf, the Tesla and Mitsubishi MiEV.

The forecast of PEVs does not include non-plug-in Hybrid Electric Vehicles (HEVs). These vehicles, such as the non-plug-in Toyota Prius, have an internal combustion engine as well as a battery and electric motor to drive the wheels. The HEV battery is charged with power from the ICE and through regenerative breaking. It is not charged by plugging in and therefore does not affect electricity consumption in Manitoba. As of March 1, 2014 and after 13 years in the market, there were only 3,960 HEVs registered in Manitoba, making up about 0.5% of all registered vehicles.

For the most part, the expected success of plug-in electric cars has not materialized worldwide. According to the Plug-In Hybrid & Electric Vehicle Research Center at UC Davis, total cumulative global sales of PHEV's and BEV's worldwide passed the 500,000 mark at the end of June, 2014. Out of the total global vehicle count of just over one billion, electric vehicles represent 0.05% of the total. The US accounts for about 45% of the total electric vehicle sales, while Japan is second, China third and the Netherlands fourth. While President Obama's goal of 1,000,000 electric vehicles on US roads by the end of 2015 seems unrealistic, according to the Centre for Solar Energy and Hydrogen Research Baden-Württemberg (ZSW), there will be over a million such vehicles on the road worldwide by the end of 2016. Range anxiety and price are cited as the main reasons for limited sales.

The Electric Vehicle Forecast

Figure 9 - Plug-In Electric Vehicles



As of March 1st, 2014, there were 67 plug-in electric passenger vehicles, plus the Manitoba Hydro Electric Bus, registered in Manitoba according to the Manitoba Public Insurance Corporation. The passenger electric vehicle registrations comprised of 27 pure electric plug-in vehicles and 40 plug-in hybrid electric vehicles. The 2013 Load Forecast had predicted a total of 103 plug-in vehicles to be registered in Manitoba at fiscal year ending 2014. The latest electric vehicle forecast is adjusted to incorporate the lower actual registrations recorded in fiscal year ending 2014. The number of new PEVs is expected to slowly increase until it reaches about 0.7% of new vehicle sales (415 per year) in 2023/24 and 4.1% of new vehicle sales (2,837 per year) in 2033/34. The total number of electric vehicles on the road is expected to be 2,057 (0.2% of total vehicle registrations) in 2023/24 and 15,910 (1.3% of total vehicle registrations) in 2033/34.

The following table provides the forecast of the number of new vehicles and total number of vehicles each year in Manitoba, as well as the corresponding numbers for Plug-In Electric Vehicles. Trailers, farm equipment and motor cycles are not included in the count. The forecast incorporates passenger as well as commercial category vehicles such as Sport Utility Vehicles (SUVs), trucks and transit buses. A passenger PEV consumes approximately 3,500 kW.h per year, equivalent to one residential electric hot water tank. An electric transit bus consumes 123,500 kW.h per year, equivalent to four electrically heated single detached dwellings.

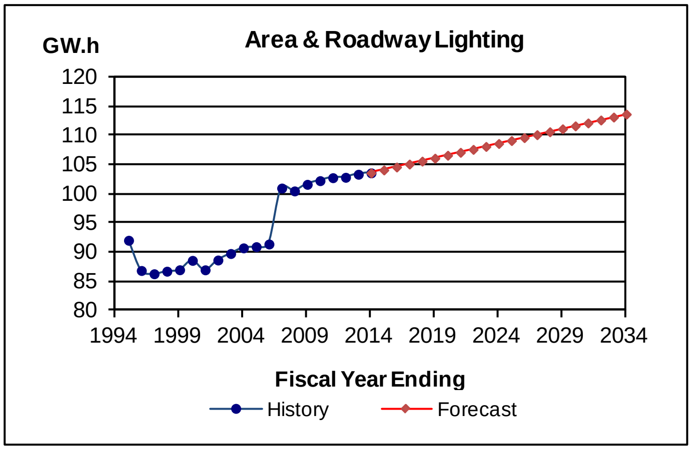
Forecast energy usage for PEVs in Manitoba is expected to be 14 GW.h in 2023/24 and 91 GW.h in 2033/34. Forecast peak usage coincident to Manitoba Hydro’s system peak is expected to be 1.8 MW in 2023/24 and 11.3 MW in 2033/34.

Table 17 - Plug-In Electric Vehicles

PLUG-IN ELECTRIC VEHICLE FORECAST History and Forecast 2003/04 - 2033/34								
Fiscal Year	New Vehicles Purchased	New PEV Purchased	New PEV %	Total Vehicles	Total PEV	Total % PEV	Cumul Total PEV GW.h	Cumul Total PEV MW
2003/04	45,691	0	0.0%	646,925	0	0.0%	0	0
2004/05	45,429	0	0.0%	657,773	0	0.0%	0	0
2005/06	46,127	0	0.0%	665,911	0	0.0%	0	0
2006/07	46,164	0	0.0%	677,922	0	0.0%	0	0
2007/08	47,953	0	0.0%	696,186	0	0.0%	0	0
2008/09	46,710	0	0.0%	711,412	0	0.0%	0	0
2009/10	44,539	0	0.0%	723,823	0	0.0%	0	0
2010/11	45,552	1	0.0%	738,299	1	0.0%	0	0
2011/12	49,177	8	0.0%	762,214	9	0.0%	0	0
2012/13	52,588	28	0.1%	779,935	37	0.0%	0	0
2013/14	56,028	31	0.1%	792,175	68	0.0%	0	0
2014/15	56,720	43	0.1%	810,759	111	0.0%	1	0.1
2015/16	57,412	67	0.1%	829,569	178	0.0%	1	0.2
2016/17	58,103	119	0.2%	848,606	298	0.0%	2	0.3
2017/18	58,795	132	0.2%	867,869	430	0.0%	4	0.4
2018/19	59,487	160	0.3%	887,360	589	0.1%	5	0.6
2019/20	60,179	193	0.3%	907,076	783	0.1%	6	0.8
2020/21	60,871	234	0.4%	927,020	1,016	0.1%	8	1.0
2021/22	61,563	283	0.5%	947,190	1,299	0.1%	10	1.2
2022/23	62,254	343	0.6%	967,587	1,642	0.2%	12	1.5
2023/24	62,946	415	0.7%	988,211	2,057	0.2%	14	1.8
2024/25	63,638	503	0.8%	1,009,061	2,561	0.3%	17	2.2
2025/26	64,330	610	0.9%	1,030,138	3,170	0.3%	21	2.6
2026/27	65,022	739	1.1%	1,051,441	3,909	0.4%	25	3.1
2027/28	65,713	896	1.4%	1,072,972	4,805	0.4%	30	3.8
2028/29	66,405	1,085	1.6%	1,094,728	5,890	0.5%	36	4.5
2029/30	67,097	1,315	2.0%	1,116,712	7,206	0.6%	43	5.4
2030/31	67,789	1,594	2.4%	1,138,922	8,800	0.8%	52	6.5
2031/32	68,481	1,932	2.8%	1,161,359	10,732	0.9%	63	7.8
2032/33	69,173	2,341	3.4%	1,184,023	13,073	1.1%	75	9.4
2033/34	69,864	2,837	4.1%	1,206,913	15,910	1.3%	91	11.3

Area & Roadway Lighting

Figure 10 - Area & Roadway Lighting



The Area and Roadway Lighting sector represents 0.5% of all sales within Manitoba. This sector includes electricity sales for the Sentinel Lighting and Street Lighting rate groups. Sentinel Lighting is an outdoor lighting service where units are available either as rentals to an existing metered service or on an unmetered, flat rate basis. Street Lighting includes all public roadway lighting in Manitoba. Energy-efficient street lighting initiatives caused the significant drop in usage in the mid 1990's. In 2006, a readjustment of the rate classes moved some flat rate General Service meters into the Lighting sector. Only Street Lights count as customers.

The Area and Roadway Lighting sector is forecast to increase from 104 GW.h in 2013/14 to 114 GW.h by 2033/34 at an average growth rate of 1 GW.h or 0.5% per year. This does not include the effect of future Demand Side Management (DSM) initiatives in this sector.

Table 18 - Area & Roadway Lighting

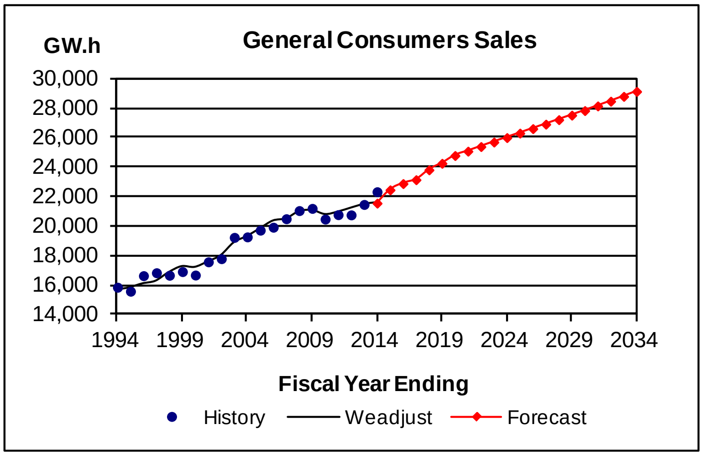
AREA & ROADWAY LIGHTING (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1994/95	92	0	92	2014/15	104
1995/96	87	0	87	2015/16	105
1996/97	86	0	86	2016/17	105
1997/98	87	0	87	2017/18	106
1998/99	87	0	87	2018/19	106
1999/00	89	0	89	2019/20	107
2000/01	87	0	87	2020/21	107
2001/02	89	0	89	2021/22	108
2002/03	90	0	90	2022/23	108
2003/04	91	0	91	2023/24	109
2004/05	91	0	91	2024/25	109
2005/06	91	0	91	2025/26	110
2006/07	101	0	101	2026/27	110
2007/08	101	0	101	2027/28	111
2008/09	102	0	102	2028/29	111
2009/10	102	0	102	2029/30	112
2010/11	103	0	103	2030/31	112
2011/12	103	0	103	2031/32	113
2012/13	103	0	103	2032/33	113
2013/14	104	0	104	2033/34	114

Table 19 - Area & Roadway Lighting

AREA AND ROADWAY LIGHTING History and Forecast 2003/04 - 2033/34								
Fiscal	Sentinal Flat Rates		Sentinal Rentals		Street Lighting		Total Lighting	
Year	(Services)	(GW.h)	(Services)	(GW.h)	(Custs)	(GW.h)	(Custs)	(GW.h)
2003/04	19,527	10	5,505	0	757	81	757	91
2004/05	19,648	10	5,519	0	759	81	759	91
2005/06	19,652	10	7,826	0	793	81	793	91
2006/07	18,669	11	23,994	0	1,129	90	1,129	101
2007/08	18,947	11	24,272	0	1,142	90	1,142	101
2008/09	19,228	11	24,542	0	1,175	91	1,175	102
2009/10	19,539	11	24,886	0	1,191	91	1,191	102
2010/11	19,835	11	25,216	0	1,184	92	1,184	103
2011/12	20,033	11	25,427	0	1,155	91	1,155	103
2012/13	20,238	12	25,613	0	1,164	92	1,164	103
2013/14	20,399	12	25,764	0	1,157	92	1,157	104
2014/15	20,560	12	25,958	0	1,160	92	1,160	104
2015/16	20,748	12	26,202	0	1,165	93	1,165	105
2016/17	20,936	12	26,446	0	1,170	93	1,170	105
2017/18	21,124	12	26,690	0	1,175	94	1,175	106
2018/19	21,312	12	26,934	0	1,180	94	1,180	106
2019/20	21,500	12	27,178	0	1,185	94	1,185	107
2020/21	21,688	12	27,422	0	1,190	95	1,190	107
2021/22	21,876	12	27,666	0	1,195	95	1,195	108
2022/23	22,064	13	27,910	0	1,200	96	1,200	108
2023/24	22,252	13	28,154	0	1,205	96	1,205	109
2024/25	22,440	13	28,398	0	1,210	96	1,210	109
2025/26	22,628	13	28,642	0	1,215	97	1,215	110
2026/27	22,816	13	28,886	0	1,220	97	1,220	110
2027/28	23,004	13	29,130	0	1,225	98	1,225	111
2028/29	23,192	13	29,374	0	1,230	98	1,230	111
2029/30	23,380	13	29,618	0	1,235	98	1,235	112
2030/31	23,568	13	29,862	0	1,240	99	1,240	112
2031/32	23,756	13	30,106	0	1,245	99	1,245	113
2032/33	23,944	14	30,350	0	1,250	100	1,250	113
2033/34	24,132	14	30,594	0	1,255	100	1,255	114

Total General Consumers Sales

Figure 11 - General Consumers Sales



General Consumers Sales includes sales to all of Manitoba Hydro's individually billed customers, but excludes export sales. This includes the total of all sales from the Residential, General Service and Lighting sectors. The General Service sector makes up about two-thirds, the Residential sector makes up about one-third and the Lighting group is only 0.5% of all sales.

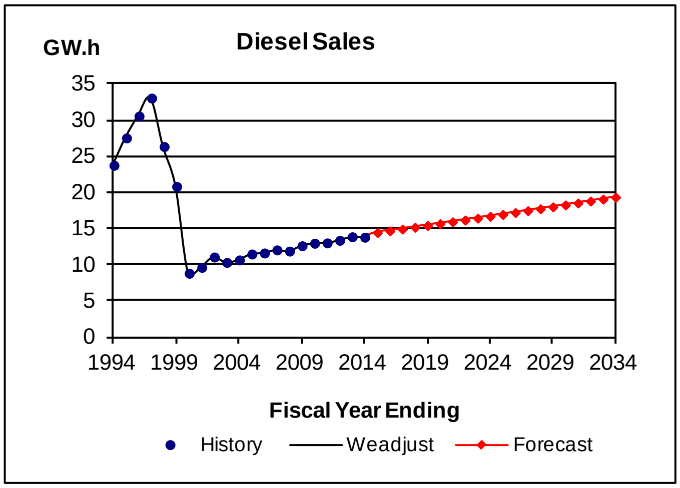
Weather adjusted General Consumers Sales has grown 301 GW.h (1.6%) per year for the past 20 years and 228 GW.h (1.1%) per year over the past 10 years. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Sales are forecast to grow 444 GW.h (1.9%) per year for the next 10 years and 378 GW.h (1.5%) per year for the next 20 years.

Table 20 - General Consumers Sales

GENERAL CONSUMERS SALES (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1994/95	15,600	249	15,848	2014/15	22,467
1995/96	16,654	-541	16,113	2015/16	22,891
1996/97	16,851	-561	16,290	2016/17	23,153
1997/98	16,681	182	16,863	2017/18	23,822
1998/99	16,929	340	17,269	2018/19	24,264
1999/00	16,696	525	17,221	2019/20	24,791
2000/01	17,590	-5	17,585	2020/21	25,087
2001/02	17,805	209	18,014	2021/22	25,399
2002/03	19,246	-376	18,871	2022/23	25,704
2003/04	19,280	11	19,291	2023/24	26,006
2004/05	19,735	78	19,813	2024/25	26,309
2005/06	19,935	398	20,333	2025/26	26,613
2006/07	20,510	-30	20,480	2026/27	26,916
2007/08	21,061	-101	20,961	2027/28	27,221
2008/09	21,210	-173	21,037	2028/29	27,527
2009/10	20,486	277	20,763	2029/30	27,836
2010/11	20,786	156	20,942	2030/31	28,151
2011/12	20,771	437	21,208	2031/32	28,471
2012/13	21,477	-22	21,455	2032/33	28,799
2013/14	22,338	-772	21,566	2033/34	29,134

Diesel Sales

Figure 12 - Diesel Sales



There are four communities served by diesel generation in Manitoba: Brochet, Lac Brochet, Tadoule Lake and Shamattawa. Sales within these communities are included in General Consumers Sales, but are not part of the Integrated System, and are thus not part of Common Bus or Gross Firm Load.

Between 1997 and 1999, eleven communities previously served by diesel generation were connected to the Integrated System resulting in the drop in overall diesel sales. The four sites that were to remain diesel were converted from 15 amp service to 60 amp service between 1991 and 2001 causing the increase in those years.

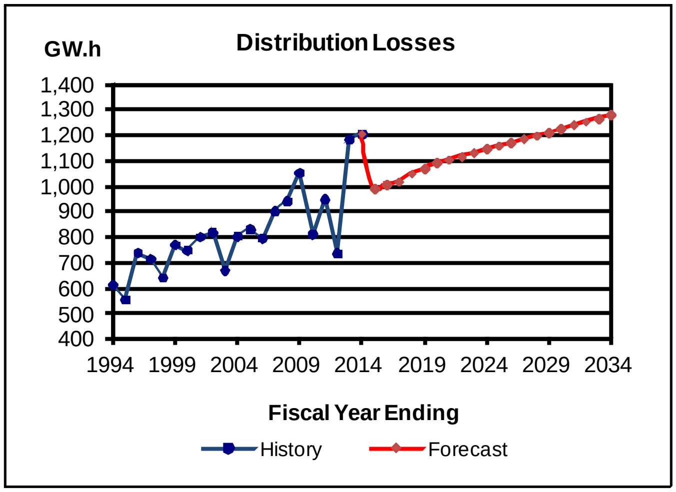
Diesel customers do not have electric heat, which requires a minimum 200 amp service, therefore there is no weather effect.

Table 21 - Diesel Sales

DIESEL SALES (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Weather Adjust	Adjusted Sales	Fiscal Year	Forecast Sales
1994/95	28	0	28	2014/15	14
1995/96	31	0	31	2015/16	15
1996/97	33	0	33	2016/17	15
1997/98	26	0	26	2017/18	15
1998/99	21	0	21	2018/19	15
1999/00	9	0	9	2019/20	16
2000/01	10	0	10	2020/21	16
2001/02	11	0	11	2021/22	16
2002/03	10	0	10	2022/23	16
2003/04	11	0	11	2023/24	17
2004/05	12	0	12	2024/25	17
2005/06	12	0	12	2025/26	17
2006/07	12	0	12	2026/27	18
2007/08	12	0	12	2027/28	18
2008/09	13	0	13	2028/29	18
2009/10	13	0	13	2029/30	18
2010/11	13	0	13	2030/31	19
2011/12	13	0	13	2031/32	19
2012/13	14	0	14	2032/33	19
2013/14	14	0	14	2033/34	19

Distribution Losses

Figure 13 - Distribution Losses



Distribution Losses are made up of the power loss between the distribution substation (Manitoba Load at Common Bus less Construction) and the customer's meter (General Consumers Sales less Diesel), as well as all other differences between what was billed and what was metered. The other differences include:

1. The offset between cycle billing (General Consumers Sales) and actual calendar month usage (Common Bus).
2. Customer Accounting adjustments,
3. Inaccuracies associated with estimated billing (including flat rate estimates),
4. The metered but unbilled consumption of Manitoba Hydro offices, and
5. Energy lost due to theft.

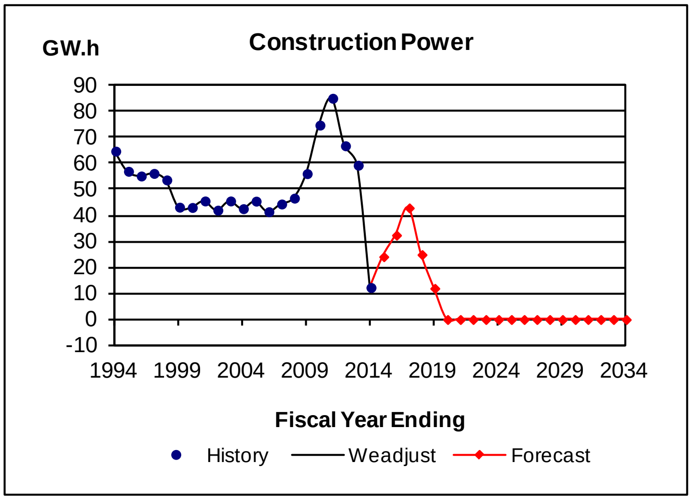
Distribution Losses are forecast in 2014/15 to be 4.4% of the General Consumers Sales less Diesel and remain at that level throughout the forecast.

Table 22 - Distribution Losses

DISTRIBUTION LOSSES (GW.h) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1994/95	556	15,572	3.6%	2014/15	988	22,452	4.4%
1995/96	740	16,623	4.4%	2015/16	1,007	22,876	4.4%
1996/97	715	16,818	4.3%	2016/17	1,018	23,138	4.4%
1997/98	641	16,655	3.9%	2017/18	1,047	23,807	4.4%
1998/99	771	16,908	4.6%	2018/19	1,067	24,249	4.4%
1999/00	749	16,687	4.5%	2019/20	1,090	24,775	4.4%
2000/01	802	17,580	4.6%	2020/21	1,103	25,071	4.4%
2001/02	819	17,793	4.6%	2021/22	1,117	25,383	4.4%
2002/03	671	19,236	3.5%	2022/23	1,130	25,688	4.4%
2003/04	804	19,269	4.2%	2023/24	1,144	25,989	4.4%
2004/05	830	19,724	4.2%	2024/25	1,157	26,292	4.4%
2005/06	797	19,923	4.0%	2025/26	1,170	26,596	4.4%
2006/07	900	20,497	4.4%	2026/27	1,184	26,898	4.4%
2007/08	940	21,049	4.5%	2027/28	1,197	27,204	4.4%
2008/09	1,052	21,198	5.0%	2028/29	1,210	27,509	4.4%
2009/10	813	20,473	4.0%	2029/30	1,224	27,818	4.4%
2010/11	947	20,773	4.6%	2030/31	1,238	28,133	4.4%
2011/12	736	20,757	3.5%	2031/32	1,252	28,452	4.4%
2012/13	1,184	21,463	5.5%	2032/33	1,266	28,780	4.4%
2013/14	1,205	22,324	5.4%	2033/34	1,281	29,115	4.4%

Construction Power

Figure 14 - Construction Power



Construction Power represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. Construction Power also includes Station Service until a plant is commissioned. Until 2013, about 48 GW.h of heating load at the Gillam, Limestone and Kettle town sites was included in Construction Power. This energy is now included in Distribution Losses.

The Construction Power forecast includes: (1) the Pointe Du Bois spillway replacement started in April 2013 with expected completion in the Fall of 2015, and (2) the Keewatinoow Converter Station, started in January 2012 with expected completion in the Fall of 2017. Construction Power does not include construction power estimates for Keeyask as they were not available at the preparation of this forecast.

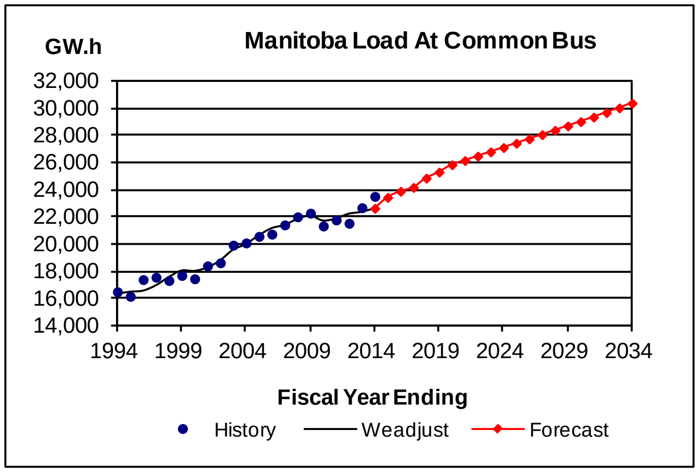
Table 23 - Construction Power

CONSTRUCTION POWER (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1994/95	57	0	57	2014/15	24
1995/96	55	0	55	2015/16	33
1996/97	56	0	56	2016/17	43
1997/98	54	0	54	2017/18	25
1998/99	43	0	43	2018/19	12
1999/00	43	0	43	2019/20	0
2000/01	46	0	46	2020/21	0
2001/02	42	0	42	2021/22	0
2002/03	46	0	46	2022/23	0
2003/04	43	0	43	2023/24	0
2004/05	46	0	46	2024/25	0
2005/06	42	0	42	2025/26	0
2006/07	45	0	45	2026/27	0
2007/08	47	0	47	2027/28	0
2008/09	56	0	56	2028/29	0
2009/10	75	0	75	2029/30	0
2010/11	85	0	85	2030/31	0
2011/12	67	0	67	2031/32	0
2012/13	59	0	59	2032/33	0
2013/14	12	0	12	2033/34	0

Manitoba Load at Common Bus

Figure 15 - Manitoba Load at Common Bus

Manitoba Load at Common Bus is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.



Common Bus is metered and totaled to correspond exactly to each calendar month. Weather adjustment is done on a calendar month basis.

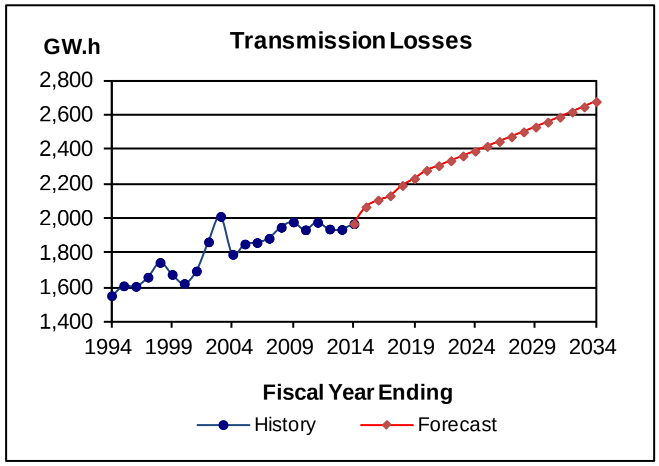
Weather adjusted Common Bus has grown 321 GW.h (1.7%) per year for the past 20 years and 262 GW.h (1.2%) per year during the past 10 years reflecting the recent economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Common Bus is forecast to grow 447 GW.h (1.8%) per year for the next 10 years and 387 GW.h (1.5%) per year for the next 20 years.

Table 24 - Manitoba Load at Common Bus

MANITOBA LOAD AT COMMON BUS (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1994/95	16,185	374	16,559	2014/15	23,464
1995/96	17,418	-782	16,635	2015/16	23,915
1996/97	17,590	-567	17,023	2016/17	24,200
1997/98	17,350	275	17,625	2017/18	24,879
1998/99	17,722	383	18,105	2018/19	25,328
1999/00	17,479	603	18,082	2019/20	25,865
2000/01	18,428	-103	18,324	2020/21	26,174
2001/02	18,655	190	18,845	2021/22	26,499
2002/03	19,953	-328	19,625	2022/23	26,818
2003/04	20,116	-76	20,040	2023/24	27,133
2004/05	20,600	77	20,677	2024/25	27,449
2005/06	20,761	438	21,199	2025/26	27,766
2006/07	21,442	-5	21,437	2026/27	28,082
2007/08	22,036	-165	21,871	2027/28	28,401
2008/09	22,305	-185	22,120	2028/29	28,719
2009/10	21,361	399	21,760	2029/30	29,042
2010/11	21,806	102	21,908	2030/31	29,370
2011/12	21,560	698	22,258	2031/32	29,704
2012/13	22,706	-314	22,392	2032/33	30,046
2013/14	23,541	-881	22,660	2033/34	30,396

Transmission Losses

Figure 16 - Transmission Losses



Transmission Losses are the amount of energy lost while delivering power from the generation stations to all of the distribution substations that make up Common Bus. Transmission Losses only contains losses associated with supplying Manitoba customers. Losses attributable to exports and the gains attributable to imports are excluded. Transmission Losses are mostly losses on the High Voltage Direct Current (HVDC) lines, and are substantial because of the distance of transmission from northern generation to southern distribution points, but are much less than what AC losses would be over that distance. Transmission Losses vary year to year depending on water conditions, system configuration, outages and the magnitude of the load. Losses were higher in 2002/03 due to two HVDC transformer failures.

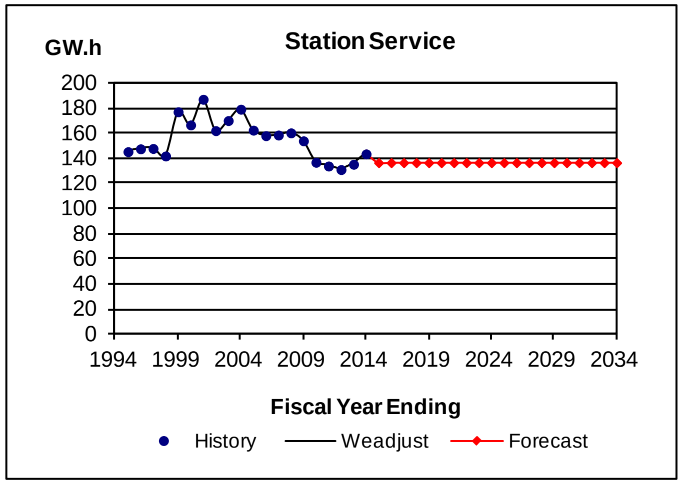
Transmission Losses are forecast to be 9.2% of the General Consumers Sales less Diesel Sales.

Table 25 - Transmission Losses

TRANSMISSION LOSSES (GW.h) HISTORICAL / PERCENT OF SALES / FORECAST							
Fiscal Year	Losses	Sales less Diesel	% Losses	Fiscal Year	Forecast Losses	Sales less Diesel	% Losses
1994/95	1,609	15,572	10.3%	2014/15	2,067	22,452	9.2%
1995/96	1,606	16,623	9.7%	2015/16	2,106	22,876	9.2%
1996/97	1,660	16,818	9.9%	2016/17	2,131	23,138	9.2%
1997/98	1,745	16,655	10.5%	2017/18	2,191	23,807	9.2%
1998/99	1,675	16,908	9.9%	2018/19	2,231	24,249	9.2%
1999/00	1,623	16,687	9.7%	2019/20	2,278	24,775	9.2%
2000/01	1,696	17,580	9.6%	2020/21	2,305	25,071	9.2%
2001/02	1,864	17,793	10.5%	2021/22	2,334	25,383	9.2%
2002/03	2,012	19,236	10.5%	2022/23	2,362	25,688	9.2%
2003/04	1,792	19,269	9.3%	2023/24	2,390	25,989	9.2%
2004/05	1,852	19,724	9.4%	2024/25	2,418	26,292	9.2%
2005/06	1,860	19,923	9.3%	2025/26	2,446	26,596	9.2%
2006/07	1,885	20,497	9.2%	2026/27	2,473	26,898	9.2%
2007/08	1,949	21,049	9.3%	2027/28	2,501	27,204	9.2%
2008/09	1,979	21,198	9.3%	2028/29	2,529	27,509	9.2%
2009/10	1,934	20,473	9.4%	2029/30	2,558	27,818	9.2%
2010/11	1,977	20,773	9.5%	2030/31	2,587	28,133	9.2%
2011/12	1,939	20,757	9.3%	2031/32	2,616	28,452	9.2%
2012/13	1,936	21,463	9.0%	2032/33	2,646	28,780	9.2%
2013/14	1,969	22,324	8.8%	2033/34	2,677	29,115	9.2%

Station Service

Figure 17 - Station Service



Station Service is the energy used by power plants to generate power and service their own load. Manitoba energy or peak without Station Service is referred to as "Net", and with Station Service as "Gross". Station Service has only been reported since 1994.

Station Service energy is forecast to be 137 GW.h and Station Service peak is forecast to be 24 MW from 2014/15 to 2033/34.

Station Service for Keeyask and for future non-committed plants is excluded from this forecast.

Table 26 - Station Service

STATION SERVICE (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Usage	Weather Adjust	Adjusted Usage	Fiscal Year	Forecast Usage
1994/95	146	0	146	2014/15	137
1995/96	148	0	148	2015/16	137
1996/97	148	0	148	2016/17	137
1997/98	142	0	142	2017/18	137
1998/99	177	0	177	2018/19	137
1999/00	167	0	167	2019/20	137
2000/01	187	0	187	2020/21	137
2001/02	162	0	162	2021/22	137
2002/03	170	0	170	2022/23	137
2003/04	179	0	179	2023/24	137
2004/05	163	0	163	2024/25	137
2005/06	158	0	158	2025/26	137
2006/07	159	0	159	2026/27	137
2007/08	161	0	161	2027/28	137
2008/09	154	0	154	2028/29	137
2009/10	137	0	137	2029/30	137
2010/11	134	0	134	2030/31	137
2011/12	131	0	131	2031/32	137
2012/13	136	0	136	2032/33	137
2013/14	144	0	144	2033/34	137

Table 27 - Monthly Station Service Energy

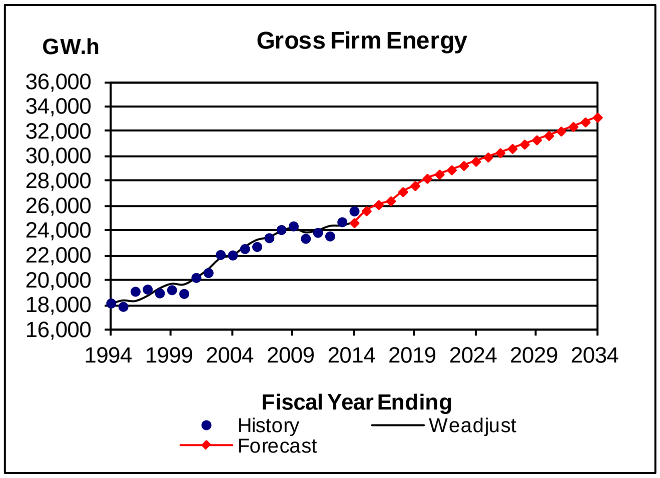
MONTHLY STATION SERVICE ENERGY (GW.h) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2003/04	16.0	11.6	9.7	11.7	12.5	12.7	13.3	17.7	18.6	23.2	16.8	15.6	179.4
2004/05	11.8	10.4	8.1	8.1	8.0	9.6	12.0	15.9	21.2	21.6	17.9	18.0	162.7
2005/06	12.6	11.0	10.0	11.1	10.1	9.6	11.8	15.2	18.4	16.7	17.0	14.9	158.3
2006/07	10.2	8.9	8.4	10.3	9.3	8.6	13.4	16.1	16.7	18.6	19.7	18.7	158.8
2007/08	15.7	12.1	9.1	8.2	8.4	7.3	8.7	14.7	19.2	18.6	19.7	18.8	160.5
2008/09	13.8	9.4	7.5	9.5	10.4	7.1	10.6	15.1	20.1	20.4	14.9	15.5	154.2
2009/10	11.8	10.3	7.9	7.2	7.4	7.2	10.8	14.2	18.8	15.5	13.3	12.7	137.1
2010/11	10.2	9.9	7.3	6.7	7.2	7.4	9.5	12.9	16.4	17.1	14.4	15.0	134.1
2011/12	12.0	9.9	7.5	7.1	7.3	6.7	9.5	13.1	15.1	16.0	13.8	13.1	131.3
2012/13	11.0	9.4	7.7	7.0	6.7	6.4	11.4	14.3	16.2	16.6	13.7	15.2	135.5
2013/14	12.6	11.1	7.0	7.5	7.6	6.9	11.2	13.5	17.8	17.0	15.8	15.8	143.8
2014/15 - 2033/34	11.9	10.1	7.4	7.2	7.2	6.7	10.7	13.7	16.3	16.5	14.4	14.7	136.8

Table 28 - Monthly Station Service Peak

MONTHLY STATION SERVICE PEAK (MW) History and Forecast													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2013/14 Actual	23	17	9	11	14	9	24	24	24	23	24	22	24
2014/15 - 2033/34	20	15	9	11	10	9	20	24	24	24	24	22	24

Gross Firm Energy

Figure 18 - Gross Firm Energy



Gross Firm Energy is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads, Diesel Sales and Station Service for Keeyask and non-committed plants.

Gross Firm Energy has grown steadily during the past twenty years, except for the economic slowdown in the 1990's and more recently in 2009.

Weather adjusted Gross Firm Energy has grown 333 GW.h (1.6%) per year for the past 20 years and 269 GW.h (1.2%) per year during the past 10 years reflecting the recent economic downturn. This historical growth includes the effect of past Demand Side Management (DSM) initiatives. Energy is forecast to grow 495 GW.h (1.8%) per year for the next 10 years and 425 GW.h (1.5%) per year for the next 20 years.

Table 29 - Gross Firm Energy

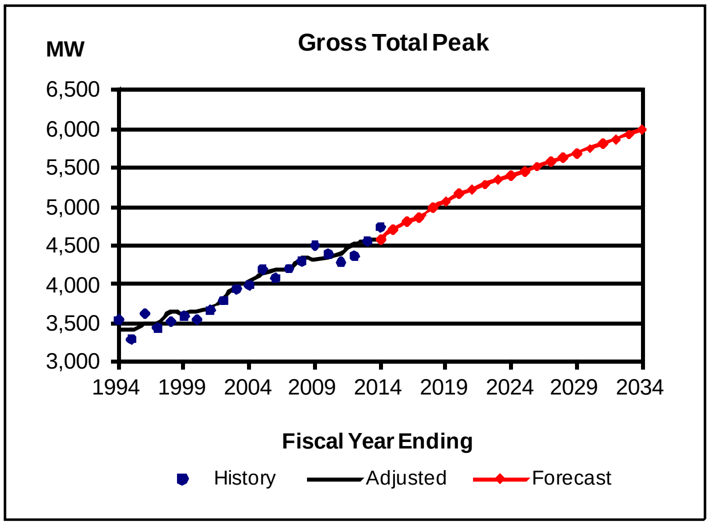
GROSS FIRM ENERGY (GW.h) HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Energy	Weather Adjust	Adjusted Energy	Fiscal Year	Forecast Energy
1994/95	17,929	413	18,343	2014/15	25,639
1995/96	19,148	-854	18,294	2015/16	26,130
1996/97	19,321	-618	18,703	2016/17	26,436
1997/98	19,014	302	19,316	2017/18	27,174
1998/99	19,273	418	19,691	2018/19	27,662
1999/00	18,971	660	19,631	2019/20	28,247
2000/01	20,262	-109	20,153	2020/21	28,583
2001/02	20,656	209	20,865	2021/22	28,937
2002/03	22,110	-360	21,750	2022/23	29,284
2003/04	22,069	-86	21,984	2023/24	29,626
2004/05	22,589	85	22,674	2024/25	29,970
2005/06	22,757	475	23,232	2025/26	30,316
2006/07	23,464	-6	23,458	2026/27	30,659
2007/08	24,122	-177	23,945	2027/28	31,006
2008/09	24,417	-199	24,218	2028/29	31,352
2009/10	23,412	436	23,848	2029/30	31,703
2010/11	23,892	114	24,006	2030/31	32,061
2011/12	23,605	758	24,362	2031/32	32,424
2012/13	24,750	-342	24,408	2032/33	32,796
2013/14	25,625	-948	24,677	2033/34	33,177

Table 30 - Monthly Gross Firm Energy

MONTHLY GROSS FIRM ENERGY (GW.h) History and Forecast 2003/04 - 2033/34													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2003/04	1,657	1,579	1,520	1,573	1,685	1,548	1,688	2,024	2,198	2,479	2,088	2,029	22,069
2004/05	1,699	1,683	1,545	1,579	1,575	1,574	1,793	1,952	2,411	2,539	2,098	2,140	22,589
2005/06	1,727	1,698	1,660	1,735	1,649	1,610	1,781	2,045	2,301	2,240	2,171	2,139	22,757
2006/07	1,712	1,690	1,681	1,826	1,746	1,622	1,870	2,092	2,303	2,458	2,304	2,159	23,464
2007/08	1,842	1,701	1,663	1,820	1,727	1,650	1,836	2,108	2,490	2,584	2,427	2,273	24,122
2008/09	1,881	1,737	1,662	1,730	1,787	1,681	1,874	2,154	2,652	2,702	2,226	2,331	24,417
2009/10	1,861	1,744	1,671	1,667	1,644	1,672	1,888	1,935	2,560	2,524	2,213	2,032	23,412
2010/11	1,699	1,692	1,611	1,716	1,698	1,638	1,778	2,129	2,563	2,682	2,322	2,364	23,892
2011/12	1,862	1,751	1,603	1,789	1,741	1,643	1,814	2,125	2,435	2,526	2,251	2,064	23,605
2012/13	1,802	1,698	1,688	1,869	1,727	1,606	1,941	2,265	2,665	2,766	2,342	2,383	24,750
2013/14	2,041	1,754	1,650	1,766	1,725	1,657	1,914	2,258	2,884	2,895	2,553	2,527	25,625
13/14 Wadj	1,842	1,778	1,665	1,801	1,678	1,683	1,895	2,218	2,636	2,800	2,371	2,310	24,677
10 Year Hist	15	14	11	21	17	17	18	26	33	46	25	27	269
Avg Growth	0.8%	0.8%	0.7%	1.2%	1.0%	1.1%	1.0%	1.3%	1.4%	1.8%	1.1%	1.2%	1.2%
2014/15	1,959	1,829	1,741	1,865	1,808	1,739	1,975	2,263	2,767	2,828	2,467	2,399	25,639
2015/16	1,996	1,864	1,774	1,900	1,842	1,773	2,012	2,306	2,820	2,882	2,514	2,445	26,130
2016/17	2,020	1,886	1,795	1,922	1,863	1,793	2,036	2,333	2,853	2,916	2,544	2,474	26,436
2017/18	2,076	1,938	1,846	1,977	1,916	1,844	2,093	2,398	2,932	2,997	2,615	2,543	27,174
2018/19	2,113	1,973	1,879	2,013	1,951	1,877	2,131	2,441	2,985	3,050	2,661	2,588	27,662
2019/20	2,157	2,015	1,919	2,056	1,993	1,917	2,176	2,492	3,047	3,115	2,717	2,643	28,247
2020/21	2,183	2,039	1,942	2,081	2,017	1,940	2,201	2,522	3,084	3,152	2,750	2,674	28,583
2021/22	2,210	2,064	1,966	2,106	2,042	1,964	2,229	2,553	3,122	3,191	2,784	2,707	28,937
2022/23	2,236	2,089	1,990	2,132	2,066	1,988	2,255	2,583	3,159	3,229	2,817	2,740	29,284
2023/24	2,263	2,113	2,013	2,157	2,090	2,011	2,282	2,614	3,196	3,267	2,850	2,772	29,626
10 Year Fcst	42	33	35	36	41	33	39	40	56	47	48	46	495
Avg Growth	2.1%	1.7%	1.9%	1.8%	2.2%	1.8%	1.9%	1.7%	1.9%	1.6%	1.9%	1.8%	1.8%
2024/25	2,289	2,138	2,036	2,182	2,114	2,034	2,308	2,644	3,233	3,305	2,883	2,804	29,970
2025/26	2,315	2,162	2,060	2,207	2,139	2,058	2,335	2,674	3,270	3,343	2,916	2,836	30,316
2026/27	2,341	2,187	2,083	2,232	2,163	2,081	2,361	2,705	3,307	3,380	2,949	2,868	30,659
2027/28	2,368	2,212	2,107	2,257	2,188	2,105	2,388	2,735	3,345	3,419	2,983	2,901	31,006
2028/29	2,394	2,236	2,130	2,282	2,212	2,128	2,415	2,766	3,382	3,457	3,016	2,933	31,352
2029/30	2,421	2,261	2,154	2,308	2,237	2,152	2,442	2,797	3,420	3,496	3,050	2,966	31,703
2030/31	2,448	2,287	2,179	2,334	2,262	2,177	2,469	2,828	3,459	3,535	3,084	2,999	32,061
2031/32	2,476	2,313	2,203	2,360	2,288	2,201	2,497	2,860	3,498	3,575	3,119	3,033	32,424
2032/33	2,505	2,339	2,229	2,387	2,314	2,226	2,526	2,893	3,538	3,616	3,155	3,068	32,796
2033/34	2,534	2,366	2,254	2,415	2,341	2,252	2,555	2,927	3,579	3,658	3,192	3,104	33,177
20 Year Fcst	35	29	29	31	33	28	33	35	47	43	41	40	425
Avg Growth	1.6%	1.4%	1.5%	1.5%	1.7%	1.5%	1.5%	1.4%	1.5%	1.3%	1.5%	1.5%	1.5%

Gross Total Peak

Figure 19 - Gross Total Peak



Gross Total Peak is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and Diesel Sales. It includes Station Service and Curtailable Loads.

Typically, the peak occurs on a very cold winter weekday either in the morning (often from 8 a.m. to 9 a.m.) or in the afternoon (from 5 p.m. to 6 p.m.) Electric heating contributes by placing the peak on one of the coldest days, whereas the operation or lack thereof of large industrials often makes the difference as to the specific day and peak hour.

The adjusted Gross Total Peak has grown from 3,403 MW in 1994/95 to 4,587 MW in 2013/14 at an average growth of 62 MW or 1.6% per year. It is forecast to grow to 5,995 MW at 70 MW (1.3%) per year by 2033/34.

Table 31 – Gross Total Peak

GROSS TOTAL PEAK (MW) HISTORICAL/ADJUSTED/FORECAST					
Fiscal Year	Peak	Adjustment	Adjusted Peak	Fiscal Year	Forecast Peak
1994/95	3,299	104	3,403	2014/15	4,716
1995/96	3,628	-151	3,477	2015/16	4,803
1996/97	3,444	49	3,493	2016/17	4,861
1997/98	3,525	122	3,647	2017/18	4,985
1998/99	3,596	21	3,617	2018/19	5,068
1999/00	3,555	98	3,653	2019/20	5,166
2000/01	3,672	13	3,684	2020/21	5,223
2001/02	3,797	4	3,800	2021/22	5,284
2002/03	3,948	31	3,979	2022/23	5,342
2003/04	3,994	38	4,033	2023/24	5,400
2004/05	4,201	-65	4,136	2024/25	5,458
2005/06	4,085	91	4,176	2025/26	5,516
2006/07	4,208	-19	4,189	2026/27	5,574
2007/08	4,304	29	4,333	2027/28	5,632
2008/09	4,509	-186	4,322	2028/29	5,690
2009/10	4,393	-48	4,345	2029/30	5,748
2010/11	4,286	115	4,401	2030/31	5,808
2011/12	4,367	155	4,523	2031/32	5,869
2012/13	4,559	-3	4,556	2032/33	5,931
2013/14	4,743	-155	4,587	2033/34	5,995

Table 32 - Monthly Gross Total Peak

MONTHLY GROSS TOTAL PEAK (MW)
History and Forecast
2003/04 - 2033/34

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2003/04	3,242	2,587	2,871	2,877	2,921	2,901	2,988	3,467	3,791	3,994	3,743	3,465	3,994
2004/05	2,868	2,773	2,713	2,893	2,632	2,748	2,980	3,598	4,057	4,201	3,843	3,577	4,201
2005/06	2,959	2,845	3,052	3,116	3,050	2,837	2,948	3,672	3,912	3,630	4,085	3,498	4,085
2006/07	3,092	2,821	3,015	3,141	3,040	2,954	3,220	3,789	4,011	4,208	4,203	3,847	4,208
2007/08	3,494	2,736	3,042	3,294	3,033	2,777	2,979	3,996	4,078	4,304	4,289	4,095	4,304
2008/09	3,221	2,893	2,952	2,920	3,110	2,726	3,159	3,804	4,427	4,509	4,196	4,223	4,509
2009/10	3,196	2,933	3,000	2,758	2,933	2,982	3,054	3,297	4,393	4,256	4,092	4,235	4,393
2010/11	2,905	2,843	2,805	2,991	3,163	2,709	3,056	3,927	4,195	4,286	4,250	4,169	4,286
2011/12	3,183	2,886	3,056	3,278	3,189	3,045	3,129	3,756	4,095	4,367	4,270	3,608	4,367
2012/13	3,328	2,775	3,161	3,260	3,253	2,870	3,312	4,087	4,410	4,559	4,543	4,013	4,559
2013/14	3,622	3,129	3,103	3,179	3,276	3,227	3,448	4,026	4,656	4,743	4,579	4,541	4,743
13/14 Norm	3,351	2,971	3,082	3,194	3,178	2,979	3,252	3,966	4,485	4,554	4,446	4,133	4,587
10 Year Hist	33	26	24	29	53	27	34	48	57	74	55	72	55
Avg Growth	1.0%	0.9%	0.8%	1.0%	1.8%	1.0%	1.1%	1.3%	1.4%	1.8%	1.3%	1.9%	1.3%
2014/15	3,445	3,055	3,168	3,283	3,267	3,063	3,343	4,077	4,611	4,682	4,571	4,249	4,716
2015/16	3,511	3,112	3,227	3,341	3,321	3,120	3,406	4,156	4,696	4,769	4,655	4,330	4,803
2016/17	3,558	3,153	3,271	3,384	3,359	3,161	3,452	4,211	4,753	4,826	4,711	4,388	4,861
2017/18	3,650	3,235	3,356	3,474	3,446	3,244	3,543	4,321	4,875	4,950	4,831	4,502	4,985
2018/19	3,713	3,292	3,416	3,537	3,507	3,301	3,605	4,396	4,956	5,033	4,912	4,580	5,068
2019/20	3,785	3,357	3,484	3,609	3,576	3,367	3,678	4,483	5,052	5,131	5,006	4,669	5,166
2020/21	3,831	3,397	3,526	3,653	3,620	3,408	3,722	4,537	5,109	5,188	5,062	4,726	5,223
2021/22	3,878	3,440	3,570	3,699	3,665	3,450	3,768	4,593	5,168	5,248	5,121	4,785	5,284
2022/23	3,924	3,481	3,613	3,743	3,709	3,491	3,813	4,648	5,225	5,306	5,178	4,842	5,342
2023/24	3,970	3,521	3,655	3,787	3,752	3,532	3,858	4,703	5,282	5,364	5,234	4,898	5,400
10 Year Fcst	62	55	57	59	57	55	61	74	80	81	79	77	81
Avg Growth	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.6%	1.6%	1.6%	1.7%	1.6%
2024/25	4,016	3,562	3,697	3,831	3,796	3,573	3,902	4,757	5,339	5,422	5,290	4,955	5,458
2025/26	4,062	3,603	3,740	3,874	3,840	3,614	3,947	4,812	5,396	5,480	5,347	5,012	5,516
2026/27	4,108	3,644	3,782	3,918	3,883	3,655	3,991	4,866	5,452	5,537	5,403	5,068	5,574
2027/28	4,154	3,685	3,824	3,962	3,927	3,696	4,036	4,921	5,509	5,595	5,459	5,126	5,632
2028/29	4,200	3,725	3,867	4,006	3,971	3,737	4,081	4,975	5,566	5,653	5,515	5,183	5,690
2029/30	4,247	3,767	3,910	4,051	4,016	3,779	4,126	5,031	5,623	5,711	5,572	5,240	5,748
2030/31	4,294	3,809	3,954	4,096	4,061	3,821	4,173	5,087	5,682	5,771	5,631	5,299	5,808
2031/32	4,343	3,852	3,998	4,143	4,107	3,865	4,220	5,145	5,741	5,831	5,690	5,359	5,869
2032/33	4,392	3,896	4,044	4,190	4,154	3,909	4,268	5,203	5,802	5,893	5,750	5,420	5,931
2033/34	4,443	3,941	4,091	4,238	4,202	3,954	4,317	5,263	5,865	5,956	5,812	5,483	5,995
20 Year Fcst	55	48	50	52	51	49	53	65	69	70	68	67	70
Avg Growth	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.3%	1.4%	1.3%

Peak load is measured and recorded differently than energy data. The system load at every hour is calculated by System Operations as:

Hourly Gross Total Peak (t)

= Hourly Total Generation (t)

- Hourly Metered Exports (t) + Hourly Metered Imports (t)

- Losses Associated with Exports (t) + Gains Associated with Imports (t)

+ Curtailments (t)

Losses for exports and gains for imports are only known on a monthly energy basis. The hourly value is obtained by using the ratio of exports/imports for the hour to the total exports/imports for the month and applying that to the total metered loss/gain for the month. The remaining difference between the balance of the load and Common Bus is taken as the Transmission Losses associated with Manitoba load.

Curtailments for individual customers are calculated as the difference between what the customer would have used if not curtailed versus what they did use. This is not the same as the calculation used for billing.

Annual Peak

The forecast annual peak is higher than the maximum of the monthly peaks. This is because the peak can occur in any one of the winter months. The same characteristic is apparent in historical peaks. The average historical annual peak is higher than the maximum of the highest average monthly peaks. For studies requiring yearly data, the annual peak should be used.

16 Hour Peak

The peaks in this document are integrated hourly peaks. For some studies and analysis of avoided cost or DSM savings, an estimate of the average peak during onpeak hours (from 6 a.m. to 10 p.m.) may be desired. To convert hourly peak to 16 hour peak, multiply the hourly peak in the associated month by the following percentages:

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
94.4%	94.9%	95.8%	96.0%	96.3%	96.0%	96.6%	95.6%	95.8%	96.6%	95.6%	95.5%	94.8%

VARIABILITY AND ACCURACY

Weather Effect and Weather Adjustment

The weather effect is determined in any sector every year by regressing the previous two years of actual monthly energies against the actual DDH and DDC for the month. This results in a GW.h per DDH effect and a GW.h per DDC effect for that sector for that year.

Only sectors whose major variation is due to weather can have a weather effect estimated. Sectors that vary primarily due to industrial output levels or seasonal but non-weather reasons may yield false weather effects if estimated. Weather effects are not determined for the GS Top Consumers, Seasonal, Diesel, Water Heating and Lighting sectors.

For sectors where a weather effect is calculated, this document will show energy as the reported value and as a weather adjusted value. Forecasts are based on the weather adjusted values. The calculations are:

Weather Adjustment = DDH weather effect * (DDH actual - DDH normal)
+ DDC weather effect * (DDC actual - DDC normal)

Weather Adjusted Actual = Actual - Weather Adjustment

Following are the DDH and DDC weather effect factors by sector:

Residential Basic: 0.6 GW.h / DDH, 1.0 GW.h / DDC
GS Mass Market: 0.3 GW.h / DDH, 1.0 GW.h / DDC
General Consumers Sales: 0.9 GW.h / DDH, 2.0 GW.h / DDC
Gross Firm Energy: 1.1 GW.h / DDH, 2.5 GW.h / DDC
Gross Total Peak: 47 MW / degree (at -30 degrees Celsius),
103 MW / degree (at +30 degrees Celsius)

Effect of Extreme Weather

A record cold winter will increase load 4% and a record warm winter will decrease it 4%. An additional 2% load increase is possible due to a record hot summer and a 1% decrease due to a record cool summer.

The effect of extreme weather is larger on a monthly basis, and even larger on a daily basis.

		Effect of Weather due to Winter Extremes on Gross Firm Energy							
	GW.h/DDH	Normal		Record Warm			Record Cold		
	1.1	DDH	GW.h	DDH	GW.h	Effect	DDH	GW.h	Effect
Year:	2014/15	4,570	25,639	3,678	24,633	-4%	5,439	26,619	4%
Month:	Jan 2015	948	2,828	663	2,506	-11%	1,261	3,181	12%
Day:	Jan 2015	31	91	6	64	-30%	56	120	31%

		Effect of Weather due to Summer Extremes on Gross Firm Energy							
	GW.h/DDC	Normal		Record Cool Summer			Record Hot Summer		
	2.5	DDC	GW.h	DDC	GW.h	Effect	DDC	GW.h	Effect
Year:	2014/15	183	25,639	69	25,355	-1%	364	26,089	2%
Month:	July 2014	69	1,865	6	1,708	-8%	142	2,045	10%
Day:	July 2014	2	60	0	55	-9%	14	89	49%

The effect of a change in temperature on the load at the time of peak due to a 5 degree temperature difference is 16% in the summer and 5% in the winter.

Summer	Winter	Effect of Change in Temperature on Gross Total Peak							
MW/Deg	MW/Deg	Normal		Warm Winter, Cool Summer			Cold Winter, Hot Summer		
103	47	Temp	MW	Temp	MW	Effect	Temp	MW	Effect
Summer	2014/15	30	3,283	25	2,766	-16%	35	3,801	16%
Winter:	2014/15	-30	4,716	-25	4,481	-5%	-35	4,951	5%

Load Variability

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession will slow energy growth and an economic boom will increase it. Cycles cannot be predicted in advance so some appropriate midpoint must be chosen as the forecast.

This forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement with an expectation of a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast. This can also be called the P50 forecast.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations), also known as P10 and P90, were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies. They are calculated as follows:

Load = Base Forecast -/+ 1.28 x Standard Deviation

For other probability points, substitute for the 1.28 the following numbers:

Prob	0.1%	2.5%	10%	20%	50%	80%	90%	97.5%	99.9%
Z(Prob)	-3.09	-1.96	-1.28	-0.84	0.00	0.84	1.28	1.96	3.09

This calculation gives the variability due to long term economic effects. It does not include variability due to weather which was removed through the use of weather adjusted load. The standard deviation of the weather variation has been found to be approximately 2% of both the energy and peak. Annual weather variations tend to be independent of the economy, so the variance due to weather can be added to the variance without weather to derive an overall variance that includes weather.

The following four charts and tables summarize the variability for energy and peak. By 2033/34, the Load Forecast has an 80% probability of being accurate to within ±2,163 GW.h or ±6.5%. Due to the inherent variability of the load, this is the best level of accuracy possible.

The overall economic standard deviation in 2033/34 is 1,688 GW.h or 5.1% of the forecast energy. Analyzed individually, the economic standard deviation of the Top Consumers sector is 1,229 GW.h (15.2%), Residential is 457 GW.h (4.9%) and Mass Market is also 457 GW.h (4.0%), showing that the Top Consumers sector is the majority of the variance.

Figure 20 - Energy Variability

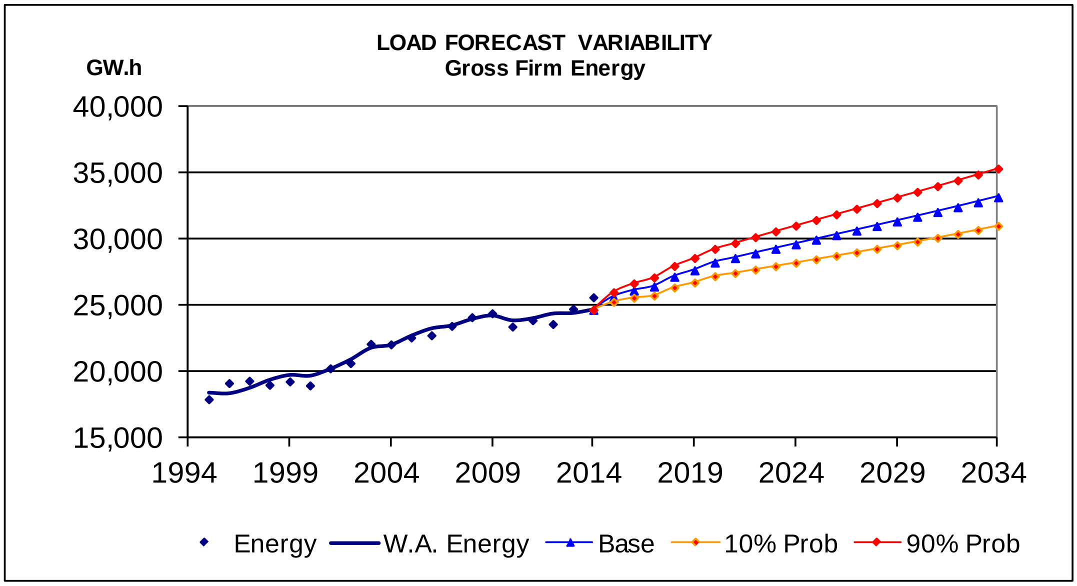


Table 33 – Energy Variability

Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2014/15	25,639	285	25,274	26,004
2015/16	26,130	424	25,586	26,673
2016/17	26,436	536	25,749	27,122
2017/18	27,174	633	26,363	27,986
2018/19	27,662	722	26,737	28,587
2019/20	28,247	804	27,217	29,277
2020/21	28,583	881	27,454	29,713
2021/22	28,937	955	27,713	30,161
2022/23	29,284	1,026	27,970	30,598
2023/24	29,626	1,093	28,225	31,028
2024/25	29,970	1,159	28,485	31,456
2025/26	30,316	1,223	28,748	31,883
2026/27	30,659	1,285	29,012	32,306
2027/28	31,006	1,346	29,281	32,731
2028/29	31,352	1,406	29,551	33,154
2029/30	31,703	1,464	29,827	33,580
2030/31	32,061	1,521	30,111	34,011
2031/32	32,424	1,578	30,403	34,446
2032/33	32,796	1,633	30,704	34,889
2033/34	33,177	1,688	31,014	35,339

Figure 21 - Peak Variability

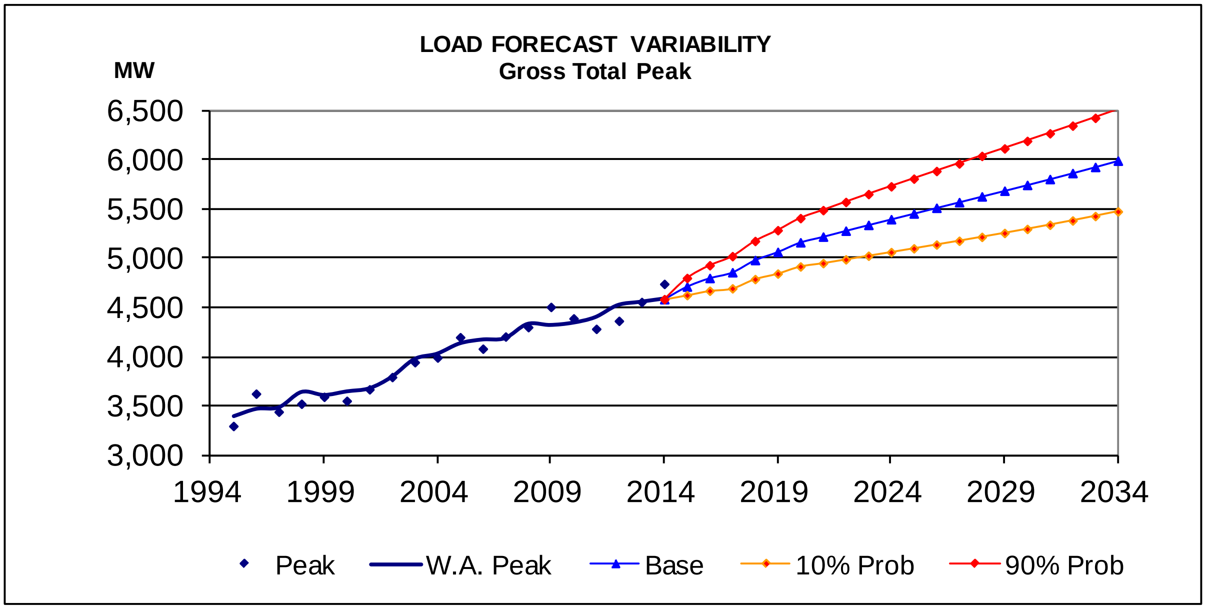


Table 34 – Peak Variability

Fiscal Year	Gross Total Peak Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2014/15	4,716	68	4,629	4,803
2015/16	4,803	101	4,673	4,932
2016/17	4,861	128	4,698	5,025
2017/18	4,985	151	4,792	5,179
2018/19	5,068	172	4,848	5,289
2019/20	5,166	192	4,920	5,411
2020/21	5,223	210	4,954	5,492
2021/22	5,284	228	4,992	5,575
2022/23	5,342	244	5,029	5,656
2023/24	5,400	261	5,066	5,734
2024/25	5,458	276	5,104	5,812
2025/26	5,516	292	5,143	5,890
2026/27	5,574	306	5,181	5,966
2027/28	5,632	321	5,221	6,043
2028/29	5,690	335	5,260	6,119
2029/30	5,748	349	5,301	6,196
2030/31	5,808	363	5,343	6,273
2031/32	5,869	376	5,387	6,351
2032/33	5,931	389	5,432	6,430
2033/34	5,995	402	5,479	6,510

5 and 10 Year Forecast Accuracy

Due just to the load variation caused by population growth and economic growth, there is only a certain level of accuracy possible. Using the load variability estimates of the previous section, it can be said that due to economic variability alone, there is less than a 50% chance that a 5 year energy forecast can be within 1.8% of the actual, and less than a 50% chance that a 10 year energy forecast can be within 2.5% of the actual.

Recognizing the inherent uncertainty of the forecast, historic forecast variation has been tracked. The following four figures and tables compare previous load forecasts to actual results 5 and 10 years later.

The energy savings achieved under Manitoba Hydro's market-based DSM programs between the year the forecast was prepared and the year being forecast was subtracted first from the forecast value. The difference is taken as the accuracy of the forecast.

The following figures and tables may seem to give the impression that there may be cycles in the forecast made up of alternating periods of over-forecasting and under-forecasting. But these are not so much due to a bias in the forecast as they are due to unexpected periods of recession or economic growth. Once one of these unexpected periods occur, it will affect the accuracy of the previous five 5-year forecasts for 5 years, and the accuracy of the previous ten 10-year forecasts for ten years.

Compensation for these periods of over and under-forecasting cannot be applied until after the events occur and only then can be identified and quantified. The forecast assumes average expected economic conditions. When that does not occur, the forecast will be high or low.

The weather adjusted Gross Firm Energy is shown in two separate columns in the Energy Accuracy table and they vary in each year due to the difference in weather normals used in each of the respected forecasts. Those weather normals differences are due to the use of a 25 year rolling average which relies on the previous 25 years of weather data at the time the forecast is created.

Figure 22 - Energy Accuracy

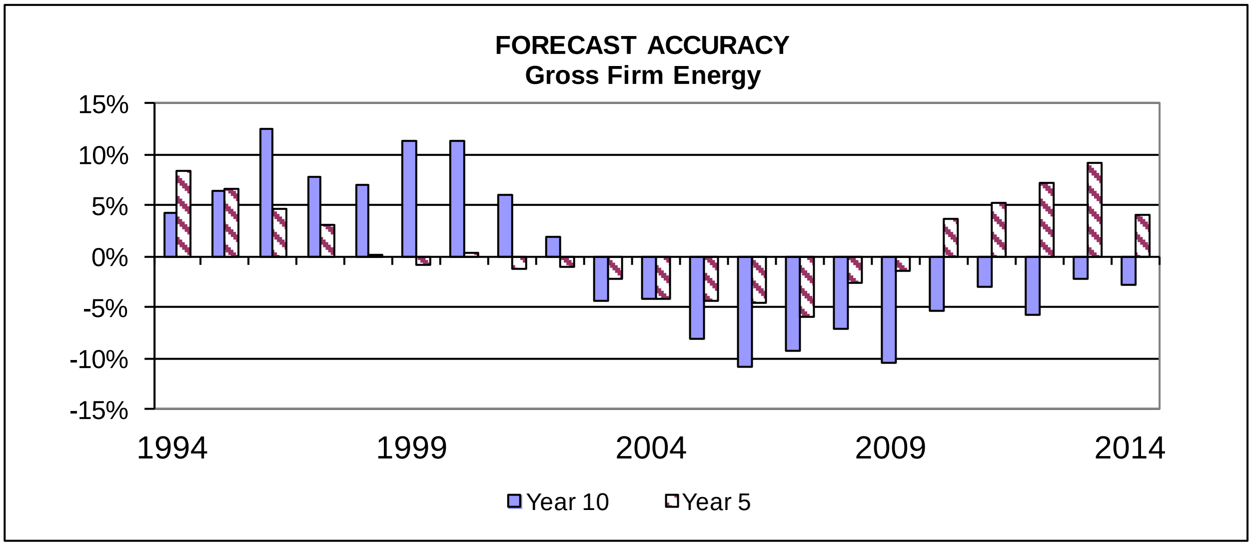


Table 35 - Energy Accuracy

Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1993/94	18,201	19,637	18,113	8.4%	18,864	18,101	4.2%
1994/95	17,929	19,597	18,365	6.7%	19,554	18,365	6.5%
1995/96	19,148	19,179	18,318	4.7%	20,659	18,370	12.5%
1996/97	19,321	19,395	18,810	3.1%	20,174	18,716	7.8%
1997/98	19,014	19,455	19,429	0.1%	20,661	19,320	6.9%
1998/99	19,273	19,675	19,818	-0.7%	21,919	19,708	11.2%
1999/00	18,971	19,767	19,703	0.3%	21,833	19,629	11.2%
2000/01	20,262	20,018	20,241	-1.1%	21,300	20,103	6.0%
2001/02	20,656	20,783	20,980	-0.9%	21,364	20,979	1.8%
2002/03	22,110	21,395	21,861	-2.1%	20,916	21,868	-4.4%
2003/04	22,069	21,134	22,062	-4.2%	21,191	22,107	-4.1%
2004/05	22,589	21,693	22,664	-4.3%	20,870	22,714	-8.1%
2005/06	22,757	22,216	23,277	-4.6%	20,812	23,346	-10.9%
2006/07	23,464	22,107	23,489	-5.9%	21,395	23,595	-9.3%
2007/08	24,122	23,353	23,962	-2.5%	22,328	24,034	-7.1%
2008/09	24,417	23,926	24,259	-1.4%	21,756	24,320	-10.5%
2009/10	23,412	24,734	23,850	3.7%	22,611	23,892	-5.4%
2010/11	23,892	25,270	24,020	5.2%	23,330	24,071	-3.1%
2011/12	23,605	25,951	24,202	7.2%	22,966	24,376	-5.8%
2012/13	24,760	26,522	24,280	9.2%	23,902	24,443	-2.2%
2013/14	25,625	25,552	24,538	4.1%	23,978	24,696	-2.9%

Figure 23 - Peak Accuracy

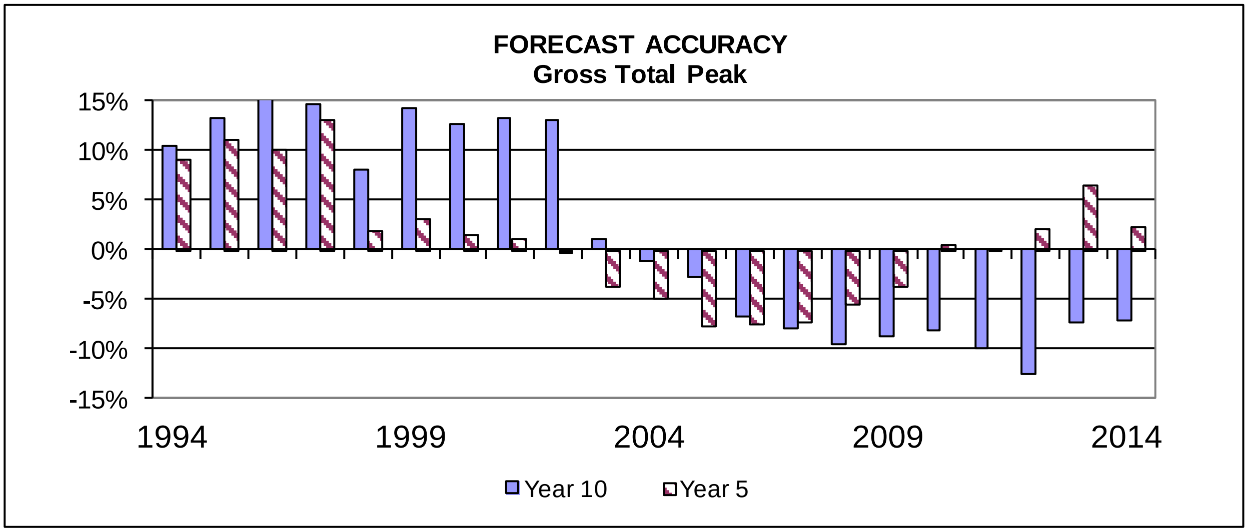


Table 36 - Peak Accuracy

Fiscal Year	Actual Gross Total Peak	Forecast Prepared 5 Years Previous	Normalized Gross Total Peak	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	Normalized Gross Total Peak	10 Year Percent Accuracy
1993/94	3,547	3,754	3,440	9.1%	3,799	3,440	10.4%
1994/95	3,299	3,829	3,446	11.1%	3,904	3,446	13.3%
1995/96	3,628	3,850	3,498	10.1%	4,081	3,498	16.7%
1996/97	3,444	3,906	3,457	13.0%	3,962	3,457	14.6%
1997/98	3,525	3,768	3,695	2.0%	3,990	3,695	8.0%
1998/99	3,596	3,703	3,593	3.1%	4,108	3,593	14.3%
1999/00	3,555	3,738	3,686	1.4%	4,152	3,686	12.6%
2000/01	3,672	3,758	3,719	1.1%	4,210	3,719	13.2%
2001/02	3,797	3,759	3,763	-0.1%	4,251	3,763	13.0%
2002/03	3,948	3,801	3,946	-3.7%	3,989	3,946	1.1%
2003/04	3,994	3,833	4,032	-4.9%	3,990	4,032	-1.1%
2004/05	4,201	3,817	4,136	-7.7%	4,023	4,136	-2.7%
2005/06	4,085	3,860	4,176	-7.6%	3,899	4,176	-6.6%
2006/07	4,208	3,894	4,202	-7.3%	3,868	4,202	-7.9%
2007/08	4,304	4,097	4,337	-5.5%	3,927	4,337	-9.5%
2008/09	4,509	4,161	4,323	-3.7%	3,948	4,323	-8.7%
2009/10	4,393	4,371	4,345	0.6%	3,993	4,345	-8.1%
2010/11	4,286	4,406	4,401	0.1%	3,967	4,401	-9.9%
2011/12	4,367	4,616	4,522	2.1%	3,952	4,522	-12.6%
2012/13	4,559	4,715	4,431	6.4%	4,108	4,431	-7.3%
2013/14	4,743	4,536	4,433	2.3%	4,119	4,433	-7.1%

LOAD SENSITIVITES AND EXTREME EVENTS

Manitoba Hydro examines the effect of possible events on the load. The information presented here provides planners with an understanding of what the potential scale of these individual events may have on the system load requirements.

The individual effects of each event can be included in scenario or sensitivity analysis if the need arises. Each change in assumption can be individually applied to the forecast as required to capture the annual energy and peak effect of the desired assumption in any given year. All values are listed at Generation and include transmission and distribution losses.

A change of 1% in annual growth rate over 20 years would be equivalent to a 20% change in any individual event. Effects are summarized below, and the details of each effect follow.

Sensitivity of the Load to a Change In Assumptions	**Annual Energy Effect (GW.h)**	**Peak Effect (MW)**
1% Increase/Decrease in Population	± 130	± 24
1% Increase/Decrease in Income and GDP	± 125	± 23
1% Increase/Decrease in Electricity Price	∓ 62	∓ 11
1% Increase/Decrease in Gas to Electricity Price Ratio	± 0.5	± 0.1
Climate Change per Degree Celsius Warmer	+ 23	- 47

Certain events may have a significant effect on the load and are provided for scenario analysis.

Evaluation of Extreme Events	**Annual Energy Effect (GW.h)**	**Peak Effect (MW)**
If 0% or 100% of Residential had Electric Space Heat	-2,733, +4,796	-891, +1,564
If 0% or 100% Residential had Electric Water Heat	-892, +928	-102, +106
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180
Maximum Potential Effect of Increased Online Shopping	- 846	- 156
Additional Load if 100% Electric Vehicle Saturation Rate	+ 4,172	+ 289
Illustrated Effect of Grid Parity (e.g. Solar Panels)	- 1,824	-104

For context, one year of energy growth is 425 GW.h and one year of peak growth is 70 MW.

Population / Economic / Price Changes

The population, economy and prices are the most significant drivers of the load in Manitoba. These variables are inputs to the econometric models utilized in this forecast. The individual effect of each driver based on the coefficients found in the models is summarized below.

Population: A 1% increase in population (12,686 people) results in a 1% increase in the number of Residential Basic customers (4,653 customers representing 74 GW.h) and a 0.60% change in the number of GS Mass Market Small and Medium customers (397 customers representing 41 GW.h). The total effect on Manitoba Gross Firm Energy would be 130 GW.h (0.53%).

Income / GDP: A 1% increase in real income results in a 0.27% increase in Residential average use (43 kW.h per customer and 20 GW.h overall). A 1% increase in Manitoba GDP results in a 0.55% increase in GS Mass Market Small and Medium average use (563 kW.h per customer totaling 37 GW.h). A 1% increase in Canada/US GDP results in 0.29% increase in GS Large Customer average use (15,934 kW.h per customer totaling 5 GW.h) and a 0.86% change in Top Consumers use (47 GW.h). The total effect of a 1% increase in Income and GDP together on Manitoba Gross Firm Energy is 125 GW.h (0.51%).

Electricity Price: A 1% increase in real electricity price results in a 0.26% decrease in Residential average use (-41 kW.h per customer totaling -19 GW.h). It will also result in a 0.12% decrease in GS Mass Market Small and Medium average use (-120 kW.h per customer totaling -8 GW.h; a 0.26% decrease in GS Mass Market Large average use (-14,213 kW.h per customer totaling -5 GW.h) and a 0.43% decrease in GS Top Consumers use (-23 GW.h). The total effect on Manitoba Gross Firm Energy is -62 GW.h (-0.25%).

Gas to Electricity Price Ratio: The gas to electricity price ratio is only modeled to affect new Residential construction therefore its effect is relatively small. A 1% increase in the ratio will result in 26 new electrically heated dwellings, with a total effect of about 0.5 GW.h.

	Energy (GW.h)	**Peak (MW)**
1% Increase/Decrease in Population	± 130	± 24
1% Increase/Decrease in Income and GDP	± 125	± 23
1% Increase/Decrease in Electricity Price	∓ 62	∓ 11
1% Increase/Decrease in Gas to Electricity Price Ratio	± 0.5	± 0.1

Climate Change

The Intergovernmental Panel on Climate Change projects an increase in global temperature as a result of rising concentrations of greenhouse gases in the atmosphere. Changes to temperature and extreme events have the potential to influence future energy demands.

In the last 100 years, the city of Winnipeg's 25-year average temperature has resulted in Degree Days Heating (DDH) in the range of 4,500 to 5,000 each year. A 25 year moving average is used for the forecast to help minimize the effects of year to year variability and to represent the long term climatology. This section quantifies the general effect caused by a 1°C increase in average daily temperature throughout the year.

In Manitoba Hydro's case, if Winnipeg experienced a uniform 1°C warming throughout the year, winter months would be subject to less heating while summer months would be subject to more cooling. Over 200 winter days, every degree Celsius of temperature rise above average conditions will result in an approximate decrease of 200 Degree Days Heating (DDH) per year, and a corresponding approximate increase of 100 Degree Days Cooling (DDC) per year over 100 summer days.

Applying the Weather effect for Manitoba Hydro at Generation gives:

Decrease of 200 DDH ➔ -225 GW.h and -47 MW in the winter

Increase of 100 DDC ➔ +248 GW.h and +103 MW in the summer

The resulting total effect of every one degree increase in temperature would be:

An increase of 23 GW.h to annual energy and a decrease of 47 MW to system peak.

	Energy (GW.h)	**Peak (MW)**
Climate Change per Degree Celsius Warmer	+23	-47

Change in Residential Use of Electricity for Space heat

Currently, 36.3% or 165,576 out of 456,130 Residential Basic customers heat their home with electricity. An increase of 1% in the percentage of customers with electric space heat would result in a change of 4,561 customers with electric space heat at 25,050 kW.h per customer, and a change of -4,561 customers without electric space at 10,572 kW.h per customer. The total Residential Basic increase would be 66 GW.h and 75 GW.h for Manitoba Gross Firm Energy. At a 35% load factor, this would be an increase of 25 MW at Peak.

If all Residential customers had electric space heat, then the additional load would be 4,796 GW.h. If no residential customers had electric space heat, then the reduction in load would be 2,733 GW.h

	Energy (GW.h)	Peak (MW)
If 0% or 100% of Residential had Electric Space Heat	-2,733, +4,796	-891, +1,564

Change in Residential Use of Electricity for Water heat

Currently, 49.0% or 223,500 out of 456,130 Residential Basic customers have electric water heat. An increase of 1% in the percentage of customers with electric water heat would result in a change of 4,561 customers with electric water heat using 3,500 kW.h per customer. The total Residential Basic increase would be 16 GW.h and 18 GW.h for Manitoba Gross Firm Energy. At a 100% load factor, this would be an increase of 2 MW at Peak.

If all Residential customers had electric water heat, then the additional load would be 928 GW.h. If no residential customers had electric space heat, then the reduction in load would be 892 GW.h

	Energy (GW.h)	Peak (MW)
If 0% or 100% Residential had Electric Water Heat	-892, +928	-102, +106

Potential Changes in Load from Very Large Industrial Customers

This forecast includes an expectation that there may be new large industrial users of electricity that may come to Manitoba. GS Top Consumers includes a Potential Large Industrial Loads category that adds 1,541 GW.h to GS Top Consumers by 2033/34. This is expected to be made up of increases and decreases by current top consumers, additions of new top consumers and company closures. However, this forecast does not anticipate the scenario of a single customer using up the entire PLIL projection.

Manitoba Hydro's largest customer currently uses in excess of 1,500 GW.h annually and has a coincident peak load of about 180 MW. It is feasible that one or more customers of this size could decide to start up in Manitoba in the next 20 years. A single large new customer could use the entire amount of energy that has been forecast under the Potential Large Industrial Loads projection.

Similarly, it is possible that one or more very large customers may discontinue operations in Manitoba. This could also be the equivalent of losing Manitoba Hydro's largest customer.

	Energy (GW.h)	Peak (MW)
Increase/Decrease of One Very Large Industrial Customer	± 1,500	± 180

Maximum Potential Load Effect of Increased Online Shopping

Online shopping is a growing service offering by many retailers. It is possible that this trend could lead to fewer retail establishments if online shopping becomes pervasive. The potential load reduction of such a scenario will be the electricity use of about 6,300 General Service customers in the Retail sector who currently use about 742 GW.h. At generation, this represents a potential total of 846 GW.h and 156 MW (using a 62% load factor). This assumes that the structures used for retail are torn down or are refurbished with other businesses that would otherwise have built a new structure.

	Energy (GW.h)	Peak (MW)
Maximum Potential Load Effect of Increased Online Shopping	-846	-156

Potential Load from High Adoption of Electric Vehicle Technology

This forecast includes the expected impact due to adoption of electric vehicles within Manitoba over the next twenty years. The specifics have been detailed in the Electric Vehicle Forecast section of this document.

It is possible that the current technological challenges will be solved, price will match those of internal combustion vehicles, and range anxiety will be alleviated. Should breakthroughs and advances in battery technology, changes in consumer perceptions, and price reductions happen in the next few years, it is possible that electric vehicles may grow to be the dominant vehicle.

The maximum load possible if 100% of all new passenger and commercial vehicles purchased every year are Plug-In Electric Vehicles (PEVs), then these vehicles would require 4,764 GW.h and 592 MW. Currently, the forecast for 2033/34 is 91 GW.h and 11 MW for PEVs, therefore the maximum additional load possible for 100% saturation would be an increase of 4,172 GW.h (10 years of load growth) and 581 MW (about 8 years of peak growth).

	Energy (GW.h)	Peak (MW)
Additional Load if 100% Electric Vehicle Saturation Rate	+4,172	+289

Illustrated Effect of Grid Parity

Grid Parity is when a customer will have an economic option to provide some or all of the electricity needs their home or business requires with an alternative energy source. Grid parity requires the self-generated kW.h cost to be competitive with utility power when considering operating, maintenance costs and a reasonable amortization period for capital costs.

Solar photovoltaic installations are frequently referenced in discussions related to grid parity as costs continue to decline. Initial adoption rates may be gradual and may take years to mature. For illustrative purposes, the effect at utility generation if 400,000 customers added solar panels each providing 4,000 kW.h per year with a 200% coincident load factor would be:

	Energy (GW.h)	Peak (MW)
Illustrated Effect of Grid Parity (e.g. Solar Panels)	-1,824	-104

ASSUMPTIONS

Economic Assumptions

Economic forecast assumptions are taken from the 2014 Economic Outlook and the 2014 Energy Price Outlook. These documents contain Manitoba Hydro's forecasts of economic variables including prices of electricity, natural gas and oil, Manitoba disposable income, Gross Domestic Product (GDP), Manitoba population and residential customers.

The following are the economic variables used in the preparation of this Electric Load Forecast:

Residential Customers - The number of Residential Basic customers in Manitoba is forecast to increase by 1.3% (5,802 units) in 2014/15 and averages 1.0% per year over the forecast period. This compares to a historical average increase of 1.0% per year over the last ten years. This is used in the Residential and GS Mass Market customer forecasts.

Electricity Prices - The electricity price forecast is based on CPI and rate increase projections used in the Integrated Financial Forecast. The real electricity price is forecast to increase by 2.2% in 2014/15, increase between 1.9% and 2.1% from 2015/16 to 2018/19 and then increase by 1.9% per year throughout the rest of the forecast period.

Natural Gas Prices – Manitoba Hydro views the natural gas price forecast as commercially sensitive information. Consistent with the Clean Environment Commission and Electric General Rate Application, this information will not be publicly disclosed. This is used in the Residential Basic forecast.

Manitoba Disposable Income - Real Manitoba disposable income annual growth was 1.2% for the past 10 years and 0.8% for the past 20 years. It is forecast to grow at 1.0% annually for the next 10 years and 1.2% annually for the next 20 years. This is used in the Residential forecast.

Gross Domestic Product (GDP) - Real economic growth in Manitoba is forecast to be 2.2% in 2014/15. It is expected to grow to 2.7% by 2016/17 and then drop to 1.6% by 2020/21 and then stay at that level for the remainder of the forecast period. This is used in the GS Mass Market and GS Top Consumer forecasts.

Normal Weather Assumptions

Weather for forecast purposes is measured by degree days. Winnipeg temperatures are used, as Winnipeg is central to most of the weather-dependent load (Residential and General Service Mass Market) in Manitoba.

Cold weather is expressed in Degree Days Heating (DDH), which is the number of average degrees colder than 14 degrees Celsius each day. Hot weather is expressed in Degree Days Cooling (DDC), which is the number of average degrees warmer than 18 degrees Celsius each day. Daily temperature is the average of the high and low temperature for the day. The equations are:

DDH = sum (max(0, 14 - (Daily high + Daily low) / 2))

DDC = sum (max(0, (Daily high + Daily low) / 2) - 18)

The base temperature of 14 degrees for DDH is the temperature below which most buildings have their heating systems (furnaces) running.

The base temperature of 18 degrees for DDC is the temperature above which buildings start to run their space cooling systems (air-conditioning).

The forecast is prepared assuming normal weather. Normal weather is determined from the 25 year average of Degree Days Heating and Degree Days Cooling in Winnipeg over the period April 1989 to March 2014.

The 25 year weather normals used for every year of this forecast are 4,569.8 DDH and 182.9 DDC. This is an increase of 28.5 DDH from last year’s normal of 4,541.3 DDH, and a decrease of 7.2 DDC from last year’s normal of 190.1 DDC.

The range of DDH from 1989 to 2014 was from a warm winter of 3,677.6 DDH in 2011/12 (892.2 DDH below normal) to a cold winter of 5,439.3 DDH in 1995/96 (869.5 DDH above normal).

The range of DDC from 1989 to 2014 was from a cool summer of 71.8 DDC in 2004/05 (111.1 DDC below normal) to a hot summer of 270.3 DDC in 1989/90 (87.4 DDC above normal).

Demand Side Management (DSM) in the Forecast

This forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards (Codes and Standards). This is the only DSM initiative that is specifically accounted for in the forecast.

Savings due to DSM programs to date are embedded in the historical data that is the basis for this forecast. The current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future Power Smart offerings and market engagement above the current level and incremental to the above mentioned Codes and Standards are treated as a supply-side resource and are not reflected in this forecast. They are accounted for separately in Manitoba Hydro's Power Smart.

As a result, historical growth rate in this document are not directly comparable to future growth rates because the history includes the effect of past DSM initiatives, but the forecast does not.

For customers involved in DSM initiatives such as the Load Displacement and Alternative Energy, the forecast excludes the effect of the initiatives, and project the load without the savings due to the initiatives.

Price / Income / GDP Elasticity

The economic effects of price, income and GDP have been incorporated into the 2014 forecast. The elasticity of each has been estimated from econometric modeling. See the Methodology section for more details. A summary of the elasticities found is:

	Price Elasticity	Real Income Elasticity	Real GDP Elasticity
Residential Basic	-0.26	0.27	
GS Mass Mkt Small/Medium	-0.12		0.55
GS Mass Mkt Large	-0.26		0.29
GS Top Consumers	-0.43		0.86
Gross Firm Energy	-0.25	0.51 (Income + GDP combined)	

METHODOLOGY

Residential Basic Methodology

The Residential Basic forecast was derived from population forecasts contained in Manitoba Hydro's 2014 Economic Outlook produced by the Economic Analysis Department, combined with an average use forecast developed from an econometric model. These results were then embedded into a residential end use model. The following components make up the end use model:

1. **Forecast Residential Dwellings** - The forecast of the total number of Residential Basic customers for the 2014/15 to 2033/34 period was taken from the 2014 Economic Outlook. The customer forecast is based on the average of several Manitoba population forecasts from various external agencies multiplied by a forecast of the people per customer ratio. The customer forecast is reduced by about 0.5% to account for customers with multiple services to obtain the forecast of individual dwellings.

2. **Determine Historical and Forecast Dwelling Breakdowns** – Historical data was taken back to 2009, the year of the last Residential Energy Use Survey. Billing data between 2009/10 and 2013/14 was used to update the survey data. The number of historical dwellings each year since 2009/10 was broken down by dwelling type (Single-Family Detached, Multi-Family Attached, and Individually-Metered Apartment suites) within each fuel region (Winnipeg, Gas Available outside Winnipeg and No Gas Available). Demolitions were estimated and the historical percentage of the number of new dwellings out of the total was applied to each regional dwelling forecast.

3. **Historical Space Heating Systems –** The number of historical dwellings by type and region were each divided into nine space heating systems: Electric Forced Air Furnace, Electric Baseboard, Electric Ground Source Heatpump, Electric Boiler, Gas High-Efficiency Furnace, Gas Mid-Efficiency Furnace, Gas Standard-Efficiency Furnace, Gas Boiler, and Other heat that is not billed for gas or electric. Starting percentages for 2009/10 were taken from the 2009 Residential Survey.

4. **Forecast of Space Heating Systems in New Dwellings** – Econometric equations were developed to forecast the number of electric space heating systems in new single detached and multi attached dwellings in Winnipeg and South Gas regions as follows:

Logit (Percentage of New Dwellings (t))

= -7.27 + 5.09 * PGEFF (lag(t))	Single Detached, Winnipeg
= -2.10 + 3.01 * PGEFF (lag(t))	Single Detached, South Gas
= -8.31 + 9.67 * PGEFF (lag(t))	Multi Attached, Winnipeg
= -2.42 + 4.91 * PGEFF (lag(t))	Multi Attached, South Gas

Logit	- A log transformation of percentages used for saturation analysis
PGEFF	- Ratio of the gas to electricity price for high efficiency furnaces
lag(t)	- The weighted average (30%, 40%, 30%) of the 3, 4 and 5 year lags

R-squared: 35.7%, 72.4%, 28.8%, 49.1%

T-stats:

Constant: -7.06, -7.53, -3.63, -3.22

PGEFF: 3.49, 7.59, 2.98, 4.61

5. **Forecast of Space Heating Systems in Existing Dwellings** – The average age of heating systems in existing dwellings was determined from the 2009 Residential Energy Use Survey. The number of replacements was estimated using a Weibull distribution based on average age of furnaces. Switches of furnace types were estimated using survey respondents in older dwellings with newer heating systems. Their former heating system was determined from billing system notes and inventory.

6. **Forecast of Water Heating Systems in New and Existing Dwellings –** Electric and natural gas water heater saturations and average age were estimated for dwellings with and without natural gas space heat using information from the 2009 Residential Energy Use Survey. The number of replacements was forecast using a Weibull distribution based on the average age of water heaters and switches between fuels were taken into account when forecasting future numbers of water heaters.

7. **Other End Uses** – Other major uses of residential electricity were forecast by dwelling type, including central air conditioning, major appliances, televisions and lighting using the saturation data from the 2009 Residential Energy Use Survey.

8. **Space Heating, Water Heating and Appliance Usage** – Conditional Demand Analysis using the 2009 Residential Survey data combined with 2009/10 customer annual use from billing data was used to derive the average annual energy use for different types of heating systems and appliances for existing and for newer dwellings. These average uses were multiplied by the number of each type of system and appliance to get the forecast of total energy use.

9. **Determine Overall Average Use** – An econometric model was used to forecast the average annual electricity use per customer of the Residential Basic sector. The Average Use per customer without Demand Side Management (DSM) programs and Codes & Standards (C&S) savings was used as the dependant variable in the econometric log model. Historical yearend data from 1989/90 to 2013/14 was modeled. The resulting model and parameters are :

   Log ((Total Use + DSM Programs + C&S) / customers)
   =6.529 + 1.596 x Ratio - 0.256 x Log Elec Price + 0.270 x LIncomeE + 0.005 x Trend

Ratio	- Electric Heat Customer Count / Total Res Basic Customer Count
Log Elec Price	- Natural Log of Manitoba Real Residential Electricity Price lagged 2.5 yrs
LIncome	- Natural Log of Manitoba Real Income per Residential Basic Customer

   R-squared: 99.4%
   T-stats:

Constant:	6.89
Ratio:	3.33
Log Elec Price:	-3.45
LIncomeE:	2.99
Trend:	5.26

10. **Determine Total GW.h used**

    The forecast number of dwellings multiplied by the overall average use determined the GW.h forecast. Annual savings estimates from the Heating Fuel Choice Initiative were subtracted, forecast Codes and Standards energy savings as outlined in the 2014-2017 Power Smart Plan 15 year Supplementary Analysis Report were subtracted, and future use of Electric Vehicles in the Residential sector was added. The result was the forecast of Residential Basic customer total energy use. This excludes savings from future Demand Side Management programs.

General Service Mass Market Methodology

A) General Service Mass Market Customer Forecast

Econometric analysis of historical sales data is used to develop models to forecast the number of General Service Mass Market customers. Forecasts of Manitoba GDP and Manitoba Hydro Residential Customers from the 2014 Economic Outlook are then input into the models, which generate forecasts for the number of customers for each year of the forecast period.

The number of customers at fiscal yearend was forecast using the following calculations for each year (t):

Number of Customers (t)
= Number of Customers (t-1)
+ Change in the Number of Customers (t)

Change in the Number of Customers (t)
= Number of Customers (t-1)
x Percentage Change in Number of Customers (t)

The percentage change in number of Small Non-Demand, Small Demand and Medium customers was modeled using yearend historical customer data from 1984/85 to 2013/14. The resulting model and parameters are as follows:

Percentage Change in Number of Customers (t)
= -0.002 + 0.129 x LCGDP + 0.601 x CRES

LCGDP	- Annual Lagged Percentage Change in Manitoba Gross Domestic Product
CRES	- Annual Percentage Change in Residential Basic Customers

R-squared: 60.6%

T-stats:

Constant:	-1.45
CGDP:	4.08
CRES:	4.19

The number of General Service Large customers was modeled using yearend historical customer data from 1989/90 to 2013/14. The resulting model and parameters are as follows:

Number of GS Large Customers (t)

= 11.694 + 0.005 x GDP

R-squared: 97.7%

T-stats:

Constant:	1.53
GDP:	31.56

B) General Service Mass Market Average Use Forecast

Historical Average Use was calculated by removing the effects of DSM and Codes & Standards. Average use for Small Non-Demand, Small Demand and Medium classes are forecast using econometric log model with Electricity Price and Manitoba GDP included in the regression.

Average Use of Small Non-Demand, Small-Demand and Medium classes were modeled using historical data from 1989/90 to 2013/14. The resulting model and parameters are as follows:

Log Average Use

=5.835 - 0.118 x Log Elec Price + 0.554 x LGDP – 0.033 x Dummy

Log Elec Price	- Natural Log of Manitoba Real GSMM Electricity Price
LGDP	- Natural Log of Manitoba Real Gross Domestic Product
Dummy	- "1" after year 2006/07, due to a billing system change causing a reclassification of customers in 2006/07.

R-squared: 98.5%

T-stats:

Constant:	10.81
Log Elec Price:	-2.03
LGDP:	13.06
Dummy:	-3.18

The Average Use for Large Mass Market customers was modeled using historical data from 1989/90 to 2013/14. The resulting model and parameters are as follows:

Log Average Use
=13.528 - 0.256 x Log Elec Price + 0.287 x LGDP

Log Elec Price - Natural Log of Manitoba Real GSMM Electricity Price
LGDP - Natural Log of Cross Real Gross Domestic Product (equally weighted on Canadian and US GDP)

R-squared: 94.2%
T-stats:

Constant:	23.23
Log Elec Price:	-2.30
LGDP:	6.47

Top Consumer customers are excluded from these classes for forecasting purposes.

Customers are assigned to a rate class depending on their usage. If usage by an individual customer increases (or decreases) sufficiently then they will be re-assigned to the appropriate rate class. These shifts tend to offset each other over time so individual classes have not shown significant upward or downward trends in average use. By definition, the truncation of these classes results in relatively stable average use for each class.

C) General Service Mass Market Total Use Forecast

General Service Mass Market customer growth is assigned to Small Non Demand, Small Demand and Medium classes by using their 5 year average use by class and allocating the customers appropriately.

Total GW.h for the General Service Mass Market sector is forecast by multiplying the forecast number of customers in each rate class by the forecast average use. Codes and Standards energy savings from the 2014-2017 Power Smart Plan 15 Year Supplementary Analysis Report were subtracted, and future use of Electric Vehicles in the Mass Market sector was added.

General Service Top Consumers Methodology

Each company in the Top Consumers group is forecast individually. Information on individual company operating plans is collected from industry news, Manitoba Hydro's economic experts and Manitoba Hydro's Key & Major Account advisors. This information is used to prepare company specific short term forecasts for committed projects that are known for the next 3 to 5 years. The company's individual forecast is then held constant for the years following.

To account for longer term energy requirements in this group of consumers, a special classification called Potential Large Industrial Loads (PLIL) has been created. PLIL is used instead of attempting to forecast each top consumer individually for the long term. It represents the natural growth or contraction of all the top consumers as a group, as well as unexpected major expansions, new customers, or loss of customers.

To forecast PLIL, an econometric model was used. Historical effects of Demand Side Management (DSM) energy savings were removed from the Top Consumer load. An econometric log model was developed by applying Top Consumer Electricity Price and equally weighted Canadian and US Real GDP.

Total Load of Top Consumers was modeled using historical data from 1983/84 to 2013/14. The resulting model and parameters are as follows:

Log Total Load

=1.477 – 0.426 x Log Top Price + 0.862 x LGDP

Log Top Price - Natural Log of Manitoba Real Top Consumers Electricity Price

LGDP - Natural Log of Cross Real Gross Domestic Product (equally weighted on Canadian and US GDP)

R-squared: 97.6%

T-stats:

Constant:	2.27
Log Top Price:	-2.95
LGDP:	15.98

Electric Vehicles

The methodology for forecasting Electric Vehicles used historical data on automobile registrations per year in Manitoba to help estimate future trends. Appropriate assumptions from recent relevant literature were applied to Manitoba's situation. The forecast section on Electric Vehicles provides further details.

Other Sectors

Seasonal, Water Heating, Lighting

Most of the smaller sales sectors, including Seasonal, Flat Rate Water Heating and Area and Roadway Lighting were done by analysis of changes in the number of customers or services and in changes in average use per customer or service. Growth rates were applied based on history and a best estimate as to what the future will bring.

Diesel

Each of the diesel generated supplied communities was individually forecast and included in the forecast under the assumption that these communities are not anticipated to be connected to the Integrated System during the forecast period.

Monthly Sales Allocations

Monthly percentages of customer growth through the year and GW.h for the month of the year were averaged for the past five years. These were applied to the forecast annual customers and kW.h to get the monthly forecast.

Monthly and Annual Gross Firm Energy and Gross Total Peak

The 5 year monthly percentage of Common Bus and Station Service are applied to their annual energy to calculate their monthly values. Transmission Losses are calculated using a 5 year average of their ratio to Common Bus. Monthly Common Bus, Transmission Losses and Station Service are added up to give the Monthly System Energy. Monthly Common Bus, Transmission Losses, Station Service and Gross Firm Energy are totaled to give the Annual Gross Firm Energy.

The Gross Total Peak is calculated from Load Factors applied to the forecast monthly Gross Total Energy. Prior to calculating the Load Factors, the Top Consumer energy and peak are subtracted because the Top Consumers have a higher average hourly energy relative to their peak value than the Residential and General Service Mass Market Customers. A 10 year historical average Load Factor is calculated for the remaining energy and is applied to the forecast monthly energy to get the peaks for the remaining energy. The Top Consumer peaks are added using an 95% Load Factor applied to the Top Consumer monthly energy.

The annual Gross Total Peak is calculated using the 3 month winter Load Factor for the winter months of December, January and February applied to the energy for the same three months.

Historical weather adjusted energy is used to calculate the annual Load Factor. The historical trend of the load factor increasing 0.1% per year is applied to the forecast. The number of hours in the month is used to calculate monthly Load Factors and the number of hours in the three winter months is used to calculate annual Load Factors.

Growth Rates

Annual GW.h/year growth rates in this document are linear growth rates, calculated as:

GW.h growth / number of years.

Annual percentage growth rates in this document are compound growth rates calculated as:

(final GW.h / initial GW.h) ^ (1 / number of years) – 1.

GLOSSARY OF TERMS

Area and Roadway Lighting sector - includes electricity sales for the Sentinel Lighting and Street Lighting rate groups.

Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers, Construction Power plus associated Distribution Losses, but excludes Diesel customers, Transmission Losses and Station Service.

Customer – Most metered electrical services count as a customer. Unmetered services such as flat rate water heating and sentinel rental services do not count as a customer. Street lighting counts all the services grouped as a premise as one customer.

Codes and Standards – A Demand Side Management (DSM) initiative associated with existing Provincial building codes and improved equipment efficiency standards. This is the only DSM initiative that is specifically accounted for in the forecast.

Curtailable - is a load that can be curtailed on short notice. A discount is given for subscribing to this program. Curtailable loads can affect peak demand because some periods of curtailment may be at or near the system peak.

Degree Days Cooling (DDC) - DDC is a measurement designed to reflect the demand for energy needed to cool a building. DDC is the number of degrees warmer than 18 degrees Celsius each day is, based on the average of the high and low temperature of the day.

DDC = sum (max(0, (Daily high + Daily low) / 2) - 18)

Degree Days Heating (DDH) – DDH is a measurement designed to reflect the demand for energy needed to heat a building. DDH is the number of degrees colder than 14 degrees Celsius each day is, based on the average of the high and low temperature of the day.

DDH = sum (max(0, 14 - (Daily high + Daily low) / 2))

Gas Available Area – A city or town in Manitoba where customers have natural gas service available and can choose to heat their dwelling with either natural gas or electricity.

Approximately 82% of Residential Basic customers, including the entire city of Winnipeg, have gas available.

General Consumers Sales - includes the energy supplied to all of Manitoba Hydro's individually billed customers. It excludes export sales.

General Service Mass Market - includes all Commercial and Industrial customers, excluding the Top Consumers group.

General Service Sector - made up of sales to Commercial and Industrial businesses served by Manitoba Hydro. This sector consists of five rate groups (Basic, Diesel, Seasonal, Flat Rate Water Heating and Surplus Energy Program).

General Service Top Consumers - is made up of the largest electricity users of Manitoba Hydro.

Gross Firm Energy - is the energy required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports, interruptible (non-firm) loads and diesel customers.

Gross Total Peak - is the maximum integrated (i.e. average) hourly load required to serve Manitoba Hydro's customers on the Integrated System. It excludes exports and diesel customers. It includes curtailable loads.

GW.h (gigawatt-hour): The unit of energy primarily used in this document. One GW.h equals one million kW.h (kilowatt-hours), which is approximately equal to the energy of 100 typical dwellings not using electricity for heating, or 40 dwellings that use electricity for heating.

Integrated System - is the power grid that connects Manitoba Hydro's generation sources to its customers. All Manitoba Hydro's customers except diesel are on the Integrated System.

Interruptible (Non-Firm) Energy - includes all energy sold to Manitoba customers on a non-firm basis. Currently, the only rate group for this is the Surplus Energy Program (SEP).

kW.h/cust (kilowatt-hours per customer): The unit of energy primarily used in this document to represent the average use of one customer. The total usage in GW.h of a group of customers is divided by the number of customers and then multiplied by one million.

Load Factor - is the ratio of the average hourly energy over a period, usually a year, divided by the energy used at a specific hour, usually the hour of system peak. A load factor of 25% means that the average energy is one-quarter of what is used at system peak. A load factor greater than 100% means that the average hourly energy is more than what is used at system peak. Given a specific energy, a lower load factor means a higher peak. The equation is:

Load Factor = (Total Energy / Hours) / (Energy over the hour of system peak)

Manitoba Load at Common Bus - is the total load measured from all the distribution points (i.e. substations) within Manitoba. It includes all energy supplied to General Consumers Sales customers plus associated Distribution Losses, but excludes diesel customers, Transmission Losses and Station Service.

MW (megawatt): The unit of peak demand primarily used in this document. One MW is a million watts. One thousand MW of peak demand for one hour equals one GW.h of energy. Alternatively, one MW for a thousand hours also equals one GW.h of energy.

Net Firm Energy and **Net Total Peak** - are the same as Gross Firm Energy and Gross Total Peak except they exclude Station Service. The reporting of Manitoba Load in the Load Forecast used “Net” until 2008. It presented both until 2011. Starting with the 2012 forecast, only the “Gross” is presented. Net can be calculated when needed by subtracting Station Service from the Gross.

Residential Basic – is the primary residential customer group made up of single detached and multi-family dwellings as well as individually metered apartment suites.

Residential sector - made up of sales to residential customers for non-business operations. The Residential sector is comprised of four rate groups (Basic, Diesel, Seasonal, and Flat Rate Water Heating).

Station Service - is the energy used by power plants to generate power and service their own load.

MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

DEMAND SIDE MANAGEMENT

INDEX

Appendices

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

DEMAND SIDE MANAGEMENT

8.0 OVERVIEW

Tab 8 provides an overview of Manitoba Hydro's Demand Side Management ("DSM") program. Section 8.1 discusses the role of DSM at Manitoba Hydro, Section 8.2 provides a summary of the current DSM plan, and Section 8.3 provides a summary of the progress of Power Smart Programs to date.

8.1 DSM'S ROLE IN FULFILLING MANITOBA HYDRO'S MANDATE

By taking an integrated approach, DSM activities play a key role in a number of the Corporation's core business activities, including:

1) Integrated Resource Planning;
2) Demand Side Management;
3) Customer Care/Service & Relationship Management; and
4) Corporate Branding/Image.

8.1.1 Integrated Resource Planning

Manitoba Hydro's mandate is to provide for the continuance of a supply of energy to meet the needs of Manitoba consumers in the most reliable, economic and environmentally sustainable manner. In fulfilling this mandate, Manitoba Hydro's mission includes promotion of economy and efficiency in the supply and end-use of energy, requiring consideration of all available options for the supply and delivery of energy to Manitobans. These options include both supply-side resources and demand-side resources with both playing a significant role in meeting the province's existing and future energy needs as outlined in Tab 9.

Through an investment of $576 million, DSM efforts to 2013/14 have achieved an estimated 768 MW and 2,481 GW.h in capacity and energy savings, and 88 million cubic metres in natural gas savings. In addition to achievements to date, Manitoba Hydro's DSM plan targets the achievement of 1,136 MW and 3,978 GWh of savings over the next 15 years, involves an investment of more than a billion dollars and will be relied upon to meet 66% of projected electricity load growth in Manitoba during this period. The electricity savings achieved through DSM is significant with the magnitude being in the same range as a number of large generating stations.

Manitoba Hydro updates its DSM plans on an annual basis to reflect new and updated information. With the passing of *The Energy Savings Act* in the spring of 2012, the process and framework for establishing DSM plans in Manitoba was changed. Key changes include:

- Manitoba Hydro is to develop the DSM plan in consultation with the Minister Responsible for Manitoba Hydro, which provides a framework for the Province to guide Manitoba Hydro's DSM targets and priorities;
- A requirement for the DSM plan to be updated annually by March 31st of each year.
- A requirement to have the results of the DSM plan reported annually by March 31st of each year.

The 2014 – 2017 Power Smart Plan was developed under this new framework.

Subject to concurrence with the Minister, Manitoba Hydro incorporates all economic opportunities in its DSM plan. The energy savings targeted in the plan are incorporated into the Corporation's long term resource plan. As such, DSM is included within Manitoba Hydro's integrated resource planning process and all economic DSM opportunities would be part of its overall plans to meet the province's future energy needs.

8.1.2 Demand Side Management

Manitoba Hydro's DSM initiative involves all activities to achieve the energy savings targeted within its DSM plan. Similar to building other long life resource options, the DSM Plan involves making a significant investment, taking a long term perspective and having broad and coordinated efforts over this period.

Manitoba Hydro's DSM Plan takes a comprehensive approach to support the efficient and productive use of energy including offering incentive based programs, education, research, support for codes and standards, rates initiatives, customer-sited self-generation for load displacement, and load management activities. In aggregate, these activities form part of an overall integrated and long term strategy to lower the demand for electricity and natural gas in Manitoba and assist customers in managing their consumption and associated energy bills. Manitoba Hydro's Power Smart strategy is to ultimately create a sustainable market change where energy efficient technologies and practices become the market standard.

Codes, standards and regulations are an important aspect of DSM programming at Manitoba Hydro, providing tools for customers to evaluate their energy performance, validating the measurement and verification of program savings, and supporting substantial energy savings through energy performance regulation today and into the future. Codes and standards implemented through energy performance regulations help cement the savings obtained from Power Smart programs designed to accelerate the transformation of markets to more energy efficient technologies, locking those savings in for future generations.

Both the Canadian Standards Association (CSA) and Natural Resources Canada (NRCAN) recognize Manitoba Hydro as a leading contributor towards the national development of codes and standards governing energy performance. Manitoba Hydro's DSM initiative actively contributes financial resources and critical technical expertise to support the work undertaken by the CSA and NRCAN to develop new codes and standards in support of their long term and comprehensive strategy to reduce energy consumption by a broad range of consumer goods, residential and commercial buildings and industrial processes.

Manitoba Hydro's strategy also engages external third parties to promote and deliver programs or components of programs through arrangements that extend from third party delivery contracts to registered suppliers. The Refrigerator Retirement, Water & Energy Savings, Commercial Kitchen – Pre Rinse Spray Valve, and Residential LED Lighting programs are a few examples of programs delivered through third party delivery contracts. Manitoba Hydro has also entered into partnership arrangements with organizations such as, but not limited to, North End Community Renewal Corporation, Brandon Neighbourhood Renewal Corporation, Building Urban Industries for Local Development (BUILD), Brandon Energy Efficiency Program (BEEP) and numerous First Nation Communities to promote and deliver energy efficiency upgrades to lower income households under the Affordable Energy Program. Manitoba Hydro is further working with AKI Energy, an aboriginal social enterprise, to promote and deliver the Community Geothermal Program in First Nation communities. To leverage industry, Manitoba Hydro has signed Power Smart agreements with 2,500 retailers and contractors actively promoting Manitoba Hydro's programs directly to customers. Industrial programs also actively leverage the capabilities of equipment suppliers and vendors to assist customers in identifying opportunities for increased energy efficiency and related productivity improvement.

8.1.3 Customer Care/Service & Relationship Management

Operationally, DSM and customer care activities are integrated to complement the Corporation's overall objective of serving its customers in a comprehensive, efficient and convenient manner. Offering DSM programs and energy services provides Manitoba Hydro with an excellent opportunity to assist customers with lowering their energy bills and concurrently the activities build positive relationships with customers, industry and stakeholders. Numerous DSM related opportunities occur on a daily basis with customers in all sectors and the depth of interactions are reflected in the participation rates under the many Power Smart programs. For example, Manitoba Hydro is working with 54 First Nation communities to implement energy efficient measures in their communities, approximately 10,000 lower income customers have participated in the Affordable Energy Program, over 850,000 customers have participated in residential programs, over 26,000 customers have participated in commercial programs and with over $300 million being provided in convenient on-bill financing.

The customer care/service & relationship management functional activities align with the Corporation's DSM activities and allow Manitoba Hydro to capture synergies to reduce overall operational costs and to provide customers with exceptional customer service through addressing customers' energy needs in a convenient approach.

8.1.4 Corporate Branding/Image

Manitoba Hydro has successfully delivered DSM initiatives for over 20 years under the "Power Smart" brand. The Power Smart brand and associated significant DSM activities have been leveraged by the Corporation to enhance its corporate image with the general public, communities, key stakeholders and all customer sectors. A significant majority of customers report that they are very satisfied with Manitoba Hydro's "Efforts to Encourage Customers to be More Energy Efficient" with 82% reporting a satisfaction level of 7 or higher on a satisfaction scale of 1 - 10.

8.2 CURRENT DSM PLAN

Manitoba Hydro has a strong commitment to DSM, focusing on pursuing all cost effective energy efficiency opportunities and continually monitoring the market for emerging trends and additional opportunities. Under Manitoba Hydro's current long range plan for DSM, "The 2014-17 Power Smart Plan – 15 Year Supplemental Report", (see Appendix 8.1), energy and demand savings resulting from Power Smart initiatives are targeted to achieve 3,978 GW.h and 1,136 MW by 2028/29. This activity represents 13% of the estimated electric load forecast offsetting 66% of projected load growth during this period. Combined with the energy savings to date, total electric savings of 6,286 GW.h and 1,635 MW will be realized by 2028/29.

Over the last year, Manitoba Hydro has introduced a number of new DSM initiatives and enhancements to existing initiatives to assist residential, commercial and industrial customers in managing their energy bills. More specifically, new programs launched include the Residential LED Lighting program, the LED Roadway Lighting Conversion Program and the Load Displacement Program. In addition, a number of enhancements to existing Power Smart programs were introduced, such as increased incentives, new measures, and enhanced sales and technical support. Some examples are as follows:

- increased insulation incentives and introduced free energy assessments for electrically heated homes;
- added direct installation of high efficiency pre-rinse spray valves to the Commercial Kitchen program;
- introduced higher performance levels beyond the new energy code for buildings, and increased incentives and technical assistance to support energy modeling under the Commercial New Buildings program;
- increased incentives under the Refrigerator Retirement, Commercial Lighting, Commercial Building Envelope, Commercial CO2 Sensors, and Commercial Refrigeration programs; and
- expanded financial and technical support for embedded energy managers in large commercial and industrial facilities under the Industrial Performance Optimization Program, accelerating the identification of efficiency improvements among Manitoba's largest energy users.

8.3 SUMMARY OF PROGRESS TO DATE

Manitoba Hydro's Power Smart Programs have been and continue to be very successful at reducing customers' energy bills while contributing to a sustainable energy supply for the needs of the Province of Manitoba as a whole. Appendix 8.2 provides the 2012/13 Power Smart Annual Review, highlighting Power Smart achievements including annual load reductions of 2,296 GW.h and 637 MW in winter peak demand reductions (at generation). These Power Smart electrical savings translate into a cumulative reduction of $660 million in customer electricity bills to date, and indirect greenhouse gas emission reductions of approximately 1,532,000 tonnes of carbon dioxide equivalent emissions in 2012/13 alone.

The energy savings realized during 2013/14 are presently being evaluated with the report expected to be finalized in the spring of 2015. The Corporation's DSM efforts are on target with estimated savings 768 MW and 2,481 GW.h as of March, 2014.

Manitoba Hydro's leadership role and continued commitment to DSM has been recognized by independent organizations including:

- In 2014, Manitoba Hydro won E Source's inaugural DSM Achievement Award for the Most Energy Savings per Customer for a gas utility. E Source benchmarked savings for portfolios from across North America and highlighted the best performing utilities in four categories.

- Manitoba Hydro's Power Smart financing programs were highlighted in a case study in the State and Local Energy Efficiency (SEE Action) Network "Financing Energy Improvements on Utility Bills: Market Updates and Key Program Design Considerations for Policymakers and Administrators" published May 22, 2014. This report, prepared by energy efficiency financing experts at the Lawrence Berkeley National Laboratory, examined best practices regarding structure and implementation of on-bill energy efficiency financing programs. Manitoba Hydro's inclusion in this report was highlighted as the company has achieved significant market penetration; having been adopted by 17 per cent of Manitoban households and representing $350 million in financing since program inception, this is the highest penetration of all 30 of the programs included in the report.

- Manitoba Hydro was asked to present their Affordable Energy Program (formally known as the Lower Income Energy Efficiency Program) at the Chartwell's Best Practices Summit on Serving Low-Income Customers in April 2009.

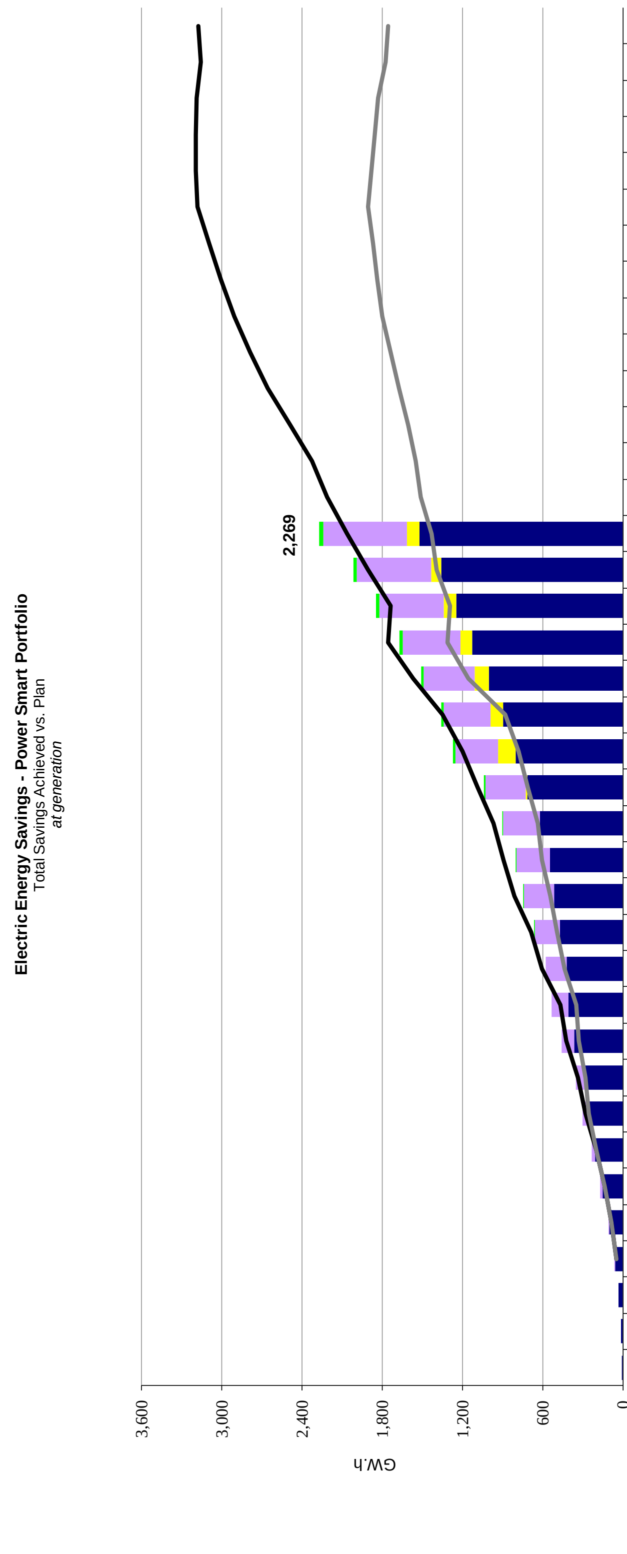
- The Canadian Energy Efficiency Alliance (CEEA), a leading non-government energy efficiency advocate, awarded Manitoba an "A+"; the highest rating awarded to any province of territory in its most recent (2009) National Report Card on Energy Efficiency. Manitoba Hydro was the key contributor to achieving this rating. This was the fourth consecutive report card covering eight years where Manitoba had either led or tied for first place in the national rating. CEEA no longer conducts these reviews.

- Manitoba Hydro's leadership and success in promoting energy efficiency in compressed air and other processes is well recognized by other utilities such as BC Hydro, Toronto Hydro and others from across North America who have contracted Manitoba Hydro to facilitate training for their industrial customers and local suppliers.

Figures 8.1 and 8.2 depict the energy and demand savings realized through to 2012/13.

1 **Figure 8.1**

2



	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Customer Service Initiatives													2	4	7	11	13	16	20	22	25	26	27	29														
Codes & Standards	-	-	-	2	8	16	25	40	63	93	125	156	189	228	248	274	298	323	352	382	430	481	553	628														
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	132	93	103	88	95	77	91														
Incentive-Based - Efficiency	6	10	31	59	99	151	209	259	285	363	407	419	467	511	546	620	715	799	895	1,002	1,126	1,243	1,356	1,521														
Plan	-			50	86	138	195	281	336	422	466	602	686	810	891	970	1,088	1,199	1,350	1,569	1,753	1,736	1,906	2063	2214	2323	2489	2654	2787	2906	3003	3096	3184	3195	3191	3186	3157	3175
Plan (Incentive-Based Programs only)	-			50	86	138	195	252	279	327	350	435	491	544	603	634	713	782	879	1,157	1,310	1,293	1391	1,427	1,509	1,551	1,608	1,675	1,737	1,796	1,835	1,871	1,902	1,881	1,858	1,832	1,771	1,754
Total Achieved	6	10	31	62	107	167	235	299	348	456	532	575	659	743	801	904	1,037	1,270	1,359	1,509	1,669	1,846	2,014	2,269														

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1 **Figure 8.2**

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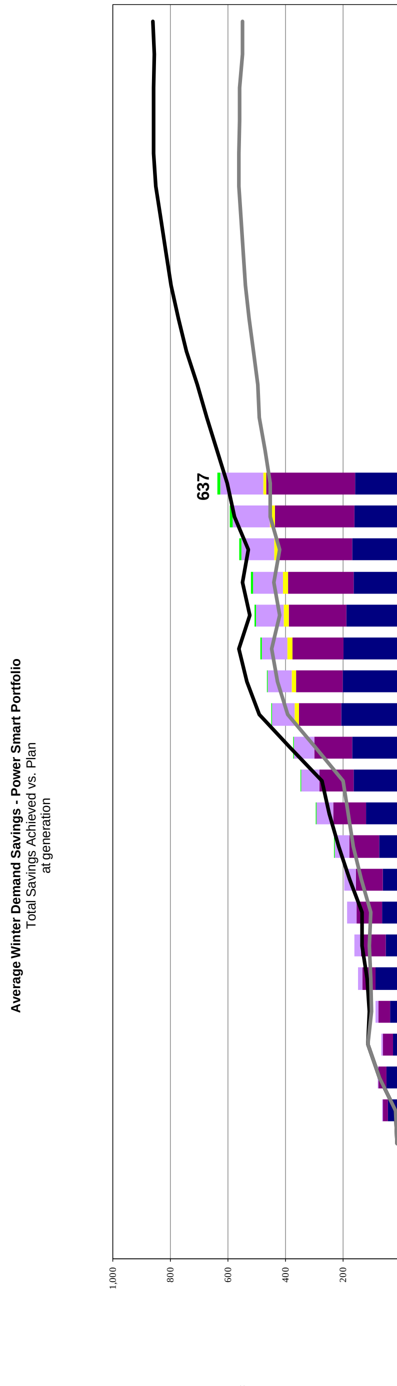


	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Customer Service Initiatives													1	1	2	3
Codes & Standards				1	2	4	6	10	15	23	32	40	49	59	64	70
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incentive-Based - Efficiency	0	1	4	10	17	26	34	42	46	86	91	93	105	113	119	131
Incentive-Based - Rate/Load	-	-	-	-	45	51	27	36	88	53	64	63	75	121	163	169
Plan				12	18	75	114	108	118	134	135	178	216	249	273	385
Plan (Incentive-Based Programs only)				12	18	75	114	101	104	110	105	136	166	183	200	296
Total	0	1	4	10	64	80	68	87	149	162	187	196	230	295	348	373

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Customer Service Initiatives	3	4	6	6	8	9	9	10														
Codes & Standards	76	82	89	97	105	113	131	150														
Incentive-Based - Customer Self Generation	16	16	16	16	16	16	16	10														
Incentive-Based - Efficiency	146	162	179	200	229	254	276	308														
Incentive-Based - Rate/Load	208	202	199	190	164	170	162	159														
Plan	491	535	564	524	551	531	578	603	638	674	707	746	773	798	816	835	852	858	858	859	856	861
Plan (Incentive-Based Programs only)	394	429	449	421	442	421	454	454	472	492	498	513	527	540	548	556	563	563	561	559	550	550
Total	450	466	488	509	521	562	594	637														

3

Power Smart Plan

2014 to 2017

SUPPLEMENTAL REPORT:
15yr (2014 to 2029)



Manitoba Hydro
POWER SMART

EXECUTIVE SUMMARY

Manitoba Hydro's 2014-2017 Power Smart Plan - 15 year supplemental report outlines the Corporation's demand side management program over the next 15 years, with some programs formally approved and placeholders used for those programs requiring further review and analysis. The Plan was developed through an intensive planning process which builds on the Corporation's experience and continuous involvement in demand side management since 1989. This plan builds upon and is consistent with the 2014-2017 three year Power Smart Plan which was prepared in consultation with the Minister responsible for Manitoba Hydro. The 15 year plan is required to accommodate the Corporation's overall longer term business planning requirements, including developing an integrated resource plan.

This supplemental report outlines the 15 year forecast of energy and demand savings, investments and cost effectiveness metrics to the benchmark year of 2028/29 which will be achieved through electricity and natural gas Power Smart Programs. The plan sets out to realize electricity savings of 1,136 MW and 3,978 GW.h, natural gas savings of 108 million cubic meters and combined global greenhouse gas emission reductions of 2.9 million tonnes by 2028/29. This activity represents 12.7% of the estimated electric load forecast offsetting 66% of projected load growth during this period and 5.3% of the estimated natural gas volume forecast by 2028/29, further reducing natural gas consumption in Manitoba. The total cost of achieving the energy savings is $978 million; $818 million of the costs are funded through the Corporation's Power Smart electricity budget, $130 million from the Power Smart natural gas budget, $11 million from the Affordable Energy Fund and $19 million from the Furnace Replacement budget for targeting furnace replacement.

Combined with energy savings achieved to date, total electrical savings of 1,635 MW and 6,286 GW.h and total natural gas savings of 211 million cubic meters will be realized by 2028/29. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 4.6 million tonnes by 2028/29. This activity represents 20.1% of the estimated electric load forecast and 10.2% of the estimated natural gas volume forecast by 2028/29. It is expected that by 2028/29, a cumulative investment of achieving the energy savings will have been $1.6 billion dollars, $1.3 billion of the costs are funded through the Corporation's Power Smart electricity budget, $232 million from the Power Smart natural gas budget, $37 million from the Affordable Energy Fund, $27 million from the Furnace Replacement budget for targeting furnace replacement.

By reducing electricity and natural gas consumption through innovative products, participating customers can expect to save $191 million in 2028/29 and $1.7 billion cumulatively by 2028/29. When combined with bill reductions to date, Power Smart programs are expected to save participating customers $277 million in 2028/29 and over $4.3 billion dollars cumulatively by 2028/29.

The overall Societal Cost (SC) and Total Resource Cost (TRC) metrics for the electric and natural gas Power Smart portfolio is 2.2 and 2.0, respectively. The electric Power Smart portfolio has an overall TRC of 2.2, RIM of 1.0 and an overall levelized utility cost of 1.8 cents per kilowatt-hour. The natural gas Power Smart portfolio has an overall TRC of 1.1, RIM of 0.5 and an overall levelized utility cost of 18.6 cents per cubic meter. Excluding the Affordable Energy Program, the natural gas Power Smart portfolio has an overall levelized utility cost of 13.5 cents per cubic meter.

APPENDIX A – 2014 –2017 Power Smart Plan Electric
Appendix A.1 - Annual Capacity Savings (MW)
Appendix A.2 - Annual Energy Savings (GW.h)
Appendix A.3 - Annual Utility Costs
Appendix A.4 - Annual Program Administration Costs
Appendix A.5 - Annual Program Incentive Costs

APPENDIX B - Historical Electric Savings & Costs
Appendix B.1 - Annual Capacity Savings (MW)
Appendix B.2 - Annual Energy Savings (GW.h)
Appendix B.3 - Annual Utility Costs
Appendix B.4 - Annual Program Administration Costs
Appendix B.5 - Annual Program Incentive Costs

APPENDIX C - 2014–2017 Power Smart Plan Natural Gas
Appendix C.1 - Annual Energy Savings (million m^3)
Appendix C.2 - Annual Utility Costs
Appendix C.3 - Annual Program Administration Costs
Appendix C.4 - Annual Program Incentive Costs

APPENDIX D - Historical Natural Gas Savings & Costs
Appendix D.1 - Annual Energy Savings (million m^3)
Appendix D.2 - Annual Utility Costs
Appendix D.3 - Annual Program Administration Costs
Appendix D.4 - Annual Program Incentive Costs

APPENDIX E - Program Evaluation Criteria
Nature of Electricity and Natural Gas Markets
Program Categories
Economic Effectiveness Metrics
Other DSM Program Assumptions

1 THE 2014-2017 POWER SMART PLAN

1.1 Introduction

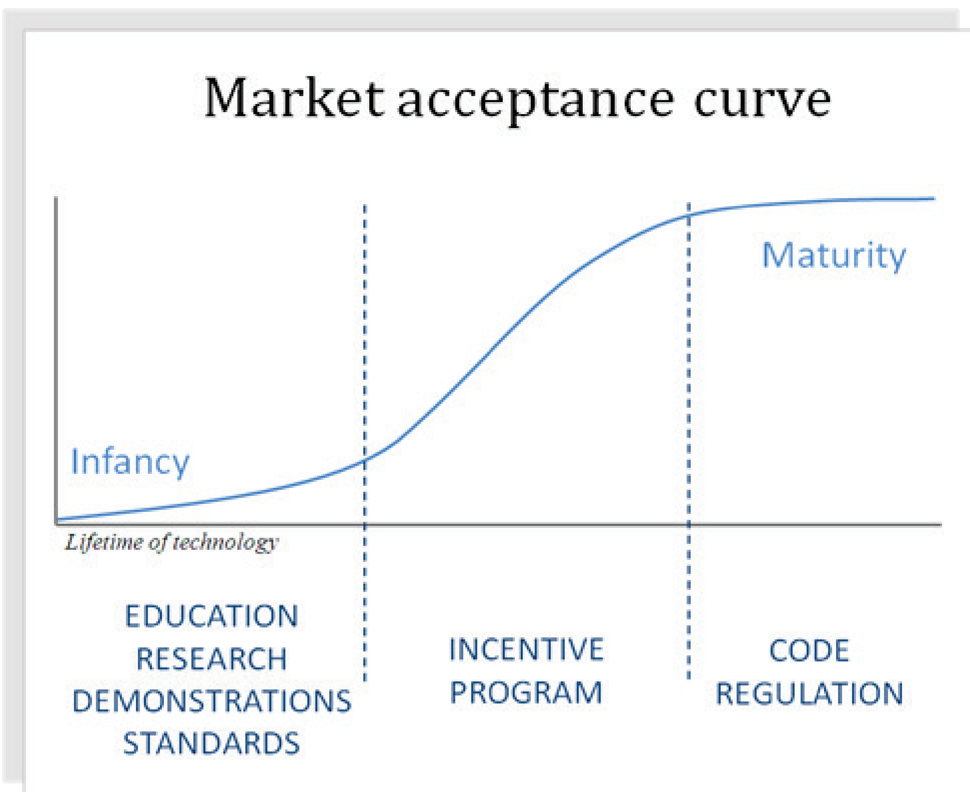
Manitoba Hydro's 2014-2017 Power Smart Plan – 15 year supplemental report outlines the Corporation's demand side management program over the next 15 years, with some programs formally approved and placeholders used for those programs requiring further review and analysis. The Plan was developed through an intensive planning process which builds on the Corporation's experience and continuous involvement in demand side management since 1989. This plan builds upon and is consistent with the 2014-2017 three year Power Smart Plan which was prepared in consultation with the Minister responsible for Manitoba in accordance with the Energy Savings Act. The 15 year plan is required to accommodate the Corporation's overall longer term business planning requirements, including developing an integrated resource plan.

Manitoba Hydro's DSM plan is an input to the development of the Corporation's Integrated Power Resource Plan. To support this process, the Corporation prepares a 15 year forecast which is reviewed and updated annually to reflect current market information and trends. This supplemental report outlines the 15 year forecast underpinning the approved 2014 – 2017 Power Smart Plan and includes the long term forecasts of energy and demand savings, budgets and cost effectiveness metrics.

1.2 DSM Market Transformation Strategy

Manitoba Hydro's DSM strategy is to aggressively pursue all cost effective energy efficiency opportunities and continually monitor the market to identify emerging trends and opportunities which may become viable and cost effective DSM initiatives within the planning horizon with the end goal of creating a sustainable market change where the energy efficient technology or practice ("EE measure") becomes the market standard.

To accomplish this in a manner that ensures permanent market transformation to the EE measure is achieved, a long term and comprehensive approach is used that involves different market intervention strategies at the various stages of the EE measure's adoption into the market. These strategies are researched and designed using a collaborative approach considering the input and expertise of the entire delivery channel for the EE measure including designers, suppliers, retailers and target customers.



Infancy

When an EE measure is first introduced to the market, it is typically received with skepticism on the part of installers, facility owners and consumers. The market is also often characterized by limited availability of the product, higher costs and, in many cases, unverified or untested energy performance claims. These conditions make it difficult to develop and increase market acceptance for the product. Lack of informed suppliers or experienced installers is also an issue with some EE measures, as many industry participants prefer to retain their own "tried and true" supply chain and installation methods.

It is of utmost importance in this phase that these barriers are addressed otherwise the EE measure will face difficulty with achieving market penetration and may fail to enter the growth stage.

Market Intervention Strategies:

Research and Development including possible demonstrations project showcasing the EE technology are important to demonstrate the performance claims for the measure and possibly to even highlight areas where the EE measure can be improved. For technologies related to space and water heating in particular, local field demonstration experience can be critical to increasing acceptance, due to Manitoba's climate differences from typical laboratory or field testing. Demonstrations also have additional benefits through the ability to become showcases for the purpose of education and a future basis for communications that incorporate "real world" experiences that installers and customers can identify with operational performance.

If the energy performance of the EE technology is already known or has been verified through research and demonstration, communication strategies focusing on education to the market are critical to building awareness of the EE measure and its benefits.

Policy relating to energy efficiency is a very powerful strategy for EE measures in the infancy stages as it encourages government stakeholders to be to become leaders with energy efficiency and be the early adopters of the new technology. Early adopters are critical to the successful launch of new EE measures as they help to build the base industry infrastructure by creating initial demand.

Growth

Once the barriers of the Infancy stage have been identified and a strategy to address the barriers has been successfully implemented for the EE measure, market penetration begins to rise, whether voluntarily or through a policy strategy. In the early stages of growth, there needs to be a balanced approach to creating demand for the measure while ensuring that the market has developed qualified and knowledgeable providers in order to meet the emerging demand. EE measures in early growth can face irreparable damage if the early majority adopters lose confidence in the measure due to performance that does not meet expectations.

At this stage, the product efficiency performance is established with energy benefits to the customer quantified and the non-energy benefits have been identified. However, there will still be a lack of knowledge in the market as to the optimum methods of realizing these benefits.

During later periods of the growth stage, installers and suppliers become more plentiful, there may be customers with years of successfully implementing the EE measure, and there is increased awareness of the existence of the product.

Through the majority of the growth phase, a first cost premium typically remains associated with the EE measure.

Power Smart can have a significant impact on the rate at which a product is adopted in the market regardless of the form of the program or support offered due to the immense trust that industry and consumers have in Manitoba Hydro's expertise in matters pertaining to energy efficiency.

Market Intervention Strategies:

The strategies that are employed during this phase are dependent upon the characteristics of the market the technology is directed toward, the magnitude and significance of the additional cost to the market, and the breadth of accommodation that must be made in order to effectively utilize the technology. Strategies can vary drastically not only by market segment but also by specific technology. A thorough understanding of the market, both overall characteristics and drivers and detractors to the EE measure, is essential to ensure that the program design is addressing the proper target market and contains the tools and strategies that will address the barriers present.

Marketing and communication strategies focus on comprehensive messaging that includes both the efficiency benefits and the non-energy benefits that have been attributed to the measure, and that have a perceived value to the intended target market, in order to maximize the market adoption.

With first cost still a barrier, many programs will utilize financial tools such as incentives and/or financing to encourage customer adoption of the measure. The specific tool used or the extent to which the program covers the incremental cost of the measure will vary by technology and by target market and, once again, involves consultation with the channel participants to determine the optimal contribution by Power Smart.

Equally as important to the more visible customer directed strategies are capacity building initiatives. These strategies can be especially important for those EE measures that rely on professional consultants or installers for implementation and include training, education, and certification of groups such as homebuilders, equipment installers, engineers, architects, retailers, and distributors.

In assessing options for pursing a Power Smart program to support an EE measure, Manitoba Hydro uses a number of metrics as guidelines to assess the opportunities. These metrics assist in determining whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and the relative investment sharing between ratepayers and participating customers.

Maturity

At the maturity phase of the EE measure's life cycle, the measure's use has become the preferred installation for the majority of the installers and customers in the market. At this stage volumes have increased to the point that prices are reduced to the same level as the technology that is being replaced, or the price of the technology is in alignment with the value perceived by the customer. With these conditions, program participants often are qualified as "free riders"; in other words, they would have adopted the measure even in the absence of a program so the incentive they received was not responsible for achieving their energy savings.

Market Intervention Strategies:

During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. A code or a regulation ensures permanent market transformation for the specific energy efficiency opportunity since a potential always exists that the market could revert back to the non-efficient option once Power Smart has reduced or eliminated its program support.

Manitoba Hydro is heavily engaged in both Federal level and Provincial level committees that work to establish ongoing updates to minimum energy performance standards for technologies and to determine the appropriateness of their adoption into a code or a regulation. The assessment of the most appropriate exit strategy for a technology is strategized as early as at the infancy phase of the adoption life cycle of the EE measure where possible.

1.3 Power Smart Programs

The following table provides program durations and cumulative participation for incentive based and financial loan programs over the 15 year planning horizon. For program descriptions, please refer to the current approved DSM plan (2014-2017 Power Smart Plan). For programs not approved but where placeholders are used, detail program descriptions are not available at this time.

Program Duration and Cumulative Participation
2014/15 - 2028/29

Programs	Program Category	Electric	Natural Gas	Program Launch Date	Particpation Definition	Cumulative Participation by 2028/29
Residential						
New Home Program	Incentive Based	√	√	Apr-2017	No. of houses	1,772
Home Insulation Program	Incentive Based	√	√	May-2004	No. of houses	25,220
Water and Energy Saver Program	Incentive Based	√	√	Sep-2010	No. of houses	335,484
Affordable Energy Program	Incentive Based	√	√	Dec-2007	No. of retrofits	24,025
Refrigerator Retirement Program	Incentive Based	√		Jun-2011	No. of appliances	31,000
Residential LED Lighting Program	Incentive Based	√		Apr-2014	No. of bulbs	328,658
Community Geothermal Program	Incentive Based	√		Apr-2013	No. of geothermal systems	5,885
Power Smart Residential Loan	Financial Loan	√	√	Feb-2001	No. of loans	90,000
Power Smart PAYS Financing	Financial Loan	√	√	Nov-2012	No. of loans	7,673
Residential Earth Power Loan	Financial Loan	√	√	Apr-2002	No. of loans	335
Commercial						
Commercial Lighting Program	Incentive Based	√		Apr-1992	No. of projects	7,315
LED Roadway Lighting Conversion Program	Incentive Based	√		Apr-2014	No. of conversions	129,550
Commercial Building Envelope - Windows Program	Incentive Based	√	√	Dec-1995	No. of projects	3,774
Commercial Building Envelope - Insulation Program	Incentive Based	√	√	Dec-1995	No. of projects	4,975
Commercial Geothermal Program	Incentive Based	√		Dec-1995	No. of buildings	1,069
Commercial HVAC Program - Boilers	Incentive Based		√	Sep-2003	No. of boilers	259
Commercial HVAC Program - Chillers	Incentive Based	√		Sep-2003	No. of chillers	89
Commercial HVAC Program - C02 Sensors	Incentive Based	√	√	Apr-2009	No. of sensors	3,339
Commercial HVAC Program - Water Heaters	Incentive Based		√	Apr-2015	No. of water heaters	462
Commercial Custom Measures Program	Incentive Based	√	√	Dec-1995	No. of projects	317
Commercial Building Optimization Program	Incentive Based	√	√	Apr-2006	No. of buildings	138
New Buildings Program	Incentive Based	√	√	Apr-2009	No. of buildings	195
Commercial Refrigeration Program	Incentive Based	√		Apr-2006	No. of locations	3,378
Commercial Kitchen Appliance Program	Incentive Based	√	√	Jan-2008	No. of appliances	5,240
Network Energy Management Program	Incentive Based	√		May-2008	No. of licenses	38,944
Internal Retrofit Program	Incentive Based	√	√	Jul-1995	No. of projects	174
Power Smart Shops	Incentive Based	√	√	Feb-2009	No. of projects	5,057
Power Smart for Business PAYS Financing	Financial Loan	√	√	Sep-2013	No. of loans	328
Industrial						
Performance Optimization Program	Incentive Based	√		Jun-1993	No. of projects	2,254
Industrial Natural Gas Optimization Program	Incentive Based		√	Sep-2006	No. of projects	48
Load Management						
Curtailable Rate Program	Incentive Based	√		Nov-1993	No. of customers	45 ^
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	Incentive Based	√	√	Mar-2006	No. of projects	54
Customer Sited Load Displacement	Incentive Based	√		Apr-2014	No. of customers	61

** Participation recurs annually*

1.4 Economic Assumptions

Marginal Costs

The 2014–17 Power Smart Plan – 15 year supplemental report incorporated the following forecasts to estimate the marginal benefits for energy savings resulting from the revenue realized from conserved electricity being sold in the export market, the avoided costs of new transmission and the supply of natural gas:

- Electric – The electric marginal cost forecast was prepared and compiled by the Resource Planning and Market Analysis Department. Marginal values were provided for savings at the distribution level, transmission level, generation level and for the value of curtailable load. For the 2014-2017 Power Smart Plan - 15 year supplemental report, the following assumptions were applied:
    - Marginal costs were based on a uniform supply with a 100% capacity factor
    - Distribution Level Programs used a loss factor of 14% to translate back to generation
    - General Service Large Programs used a loss factor of 10% to translate back to generation
    - Generation Level Programs used a loss factor of 14% to translate to distribution level
    - US/Cdn Exchange Rates and Escalation Factors were derived from the Corporation's G911 corporate policy document issued August 13th, 2013
    - Transmission & distribution marginal costs were updated using SPD 2010/02

- Natural Gas – The marginal cost forecast for natural gas was prepared based on the natural gas price forecast which was provided by the Economic Analysis Department. Unlike the price forecast, it does not include distribution costs. The benefits of avoided greenhouse gas emissions were included in the natural gas marginal benefits used to calculate the Societal Cost (SC) and Total Resource Cost (TRC) metric. A greenhouse gas cost forecast was provided by the Energy Policy & Analysis Department.

- In addition, water benefits were calculated based on 2014 City of Winnipeg Water and Sewer rates effective April 1st, 2014.

Customer Rates

The following forecasts were used to determine the impact of customer bill reductions resulting from their Power Smart energy savings:

- Electric – The Electric Rates & Regulatory Department provided the rate forecast for electricity. Commercial and industrial program rates were determined by a weighted average based on the forecast participation by each of the Corporations' billing classes. Residential rates were consistent for all residential programs. For the 2014-2017 Power Smart Plan - 15 year supplemental report, the weighted rates were based on the approved May 1st, 2013 rate forecast which assumed the 2014/15 real rates would increase by 1.9% and thereafter by 1.9% per year. This was based on the projected rate increase of 3.95% for 2014/15 and the long term rate increase of 3.95% per year (as per IFF-12) less the 2014/15 escalation rate of 2.0 % and the long term escalation rate of 2.0% (2012 Economic Outlook), (represented in 2014 $).

- Natural Gas – The natural gas price forecast was prepared by the Economic Analysis Department with input from the Energy Price Outlook. For the 2014-2017 Power Smart Plan - 15 year supplemental report, the following assumptions were applied:
  - Forecast starting point was the February 1st, 2013 rate
  - Commodity price changes into the future were based on the forecast of natural gas prices contained in the Energy Price Outlook which represented a consensus view of futures markets and a suite of five independent forecasting organizations
  - Non-commodity (monthly charge, transportation, distribution) price changes were based on IFF-12 assumptions on general rate increases and the Economic Outlook assumptions on Manitoba inflation. Non-commodity price changes in the post-IFF period were based on historical trends

Economic Variables

For the 2014-2017 Power Smart Plan - 15 year supplemental report, the Projected Escalation, Interest, & Exchange Rates – G911 corporate policy document issued August 13th, 2013 was used to discount all forward-looking savings and costs. The real weighted average cost of capital of 5.4% was used to discount real dollar cash flows and energy savings. Rates for all historical benefits, costs, and energy savings used actual economic results for each year.

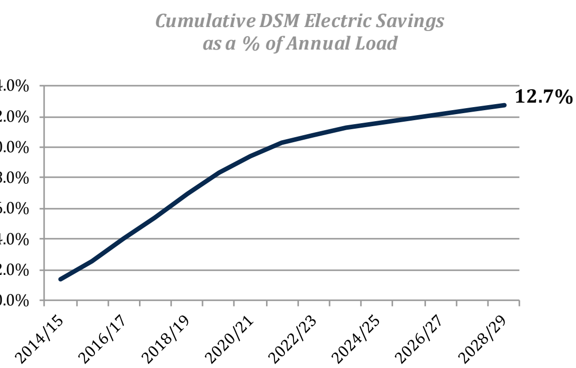
2 DEMAND SIDE MANAGEMENT

2.1 DSM Targets

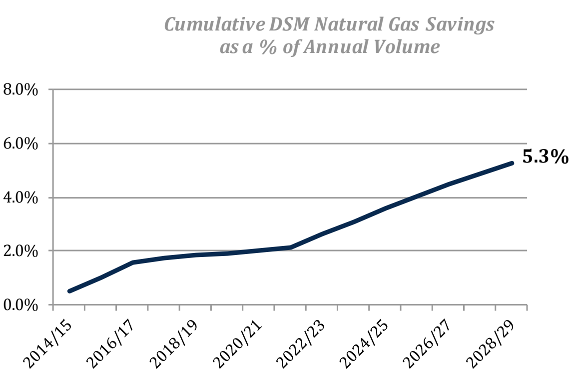
2.1.1 Electric and Natural Gas DSM Savings

In summary, the plan sets out to realize electricity savings of 1,136 MW and 3,978 GW.h, natural gas savings of 108 million cubic meters and combined global greenhouse gas emission reductions of 2.9 million tonnes by 2028/29.

This demand side management plan represents 12.7% of the estimated electric load forecast offsetting 66% of projected load growth during this period and 5.3% of the estimated natural gas volume forecast by 2028/29, further reducing natural gas consumption in Manitoba.



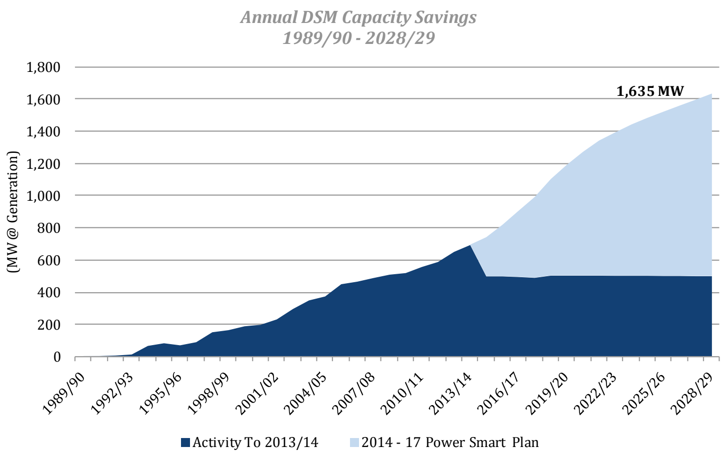
Note: Total DSM Electric savings per the above graph includes forecast savings from program impacts and savings from Codes, Standards and Regulations.
Source of Load Forecast: 2013 Electric Load Forecast

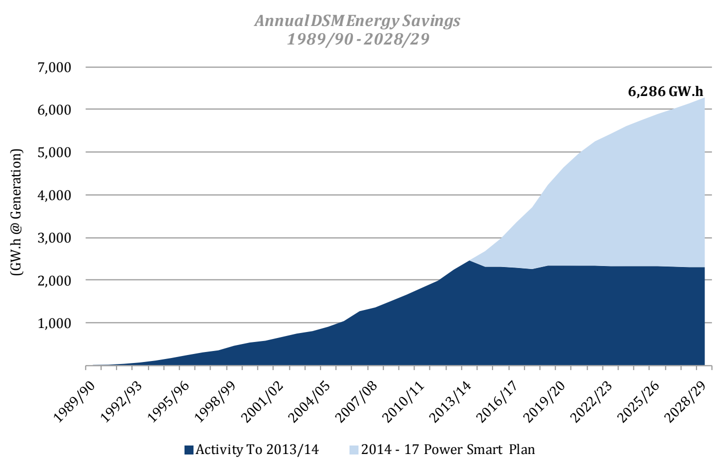


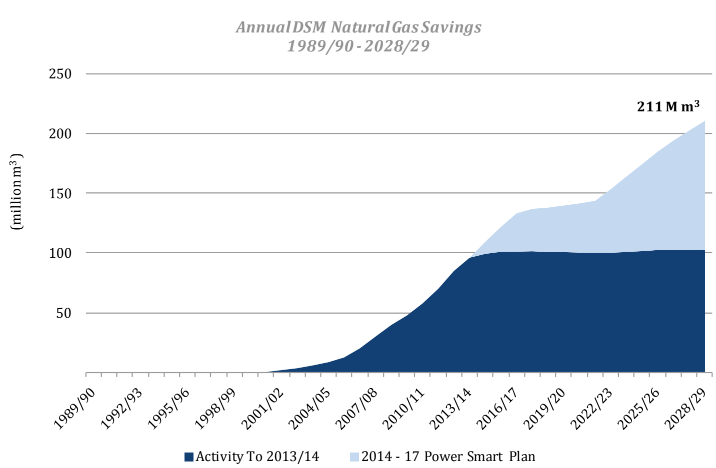
Note: Total DSM Natural Gas savings per the above graph includes forecast savings from program impacts and Codes, Standards and Regulations
Source of Natural Gas Volume Forecast: 2013 Natural Gas Volume Forecast

Combined with energy savings achieved to date, total electrical savings of 1,635 MW and 6,286 GW.h and total natural gas savings of 211 million cubic meters will be realized by 2028/29. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 4.6 million tonnes by 2028/29. This activity represents 20.1% of the estimated electric load forecast and 10.2% of the estimated natural gas volume forecast by 2028/29.

The following charts graphically represent the capacity, electric energy and natural gas energy savings achieved to date and the savings anticipated from future DSM activity for the 2014-2017 Power Smart Plan - 15 year supplemental report:







The following table shows detailed DSM savings associated with the 2014-2017 Power Smart Plan - 15 year supplemental report by sector to 2028/29.

Electric and Natural Gas DSM Savings
2014/15 - 2028/29

	Annual Capacity (MW)		Annual Energy (GW.h)		Annual Energy (million m^3)	
Residential						
New Home Program	12.0		39.9		6.4	
Home Insulation Program	16.8		31.2		8.9	
Water and Energy Saver Program	2.4		12.3		2.5	
Affordable Energy Program						
Affordable Energy Program - Insulation	15.6		31.1		6.1	
Affordable Energy Program - Furnace	n/a		n/a		0.0	
Affordable Energy Program - Total	15.6		31.1		6.1	
Refrigerator Retirement Program	0.2		1.5		0.0	
Residential LED Lighting Program	1.4		5.9		0.0	
Community Geothermal Program	15.7		59.7		0.0	
Residential Programs Total (@ Meter)	64.1	10%	181.7	7%	23.9	74%
Customer Service Initiatives / Financial Loan Programs						
Power Smart Residential Loan	3.9		7.5		4.6	
Power Smart PAYS Financing	1.4		5.2		0.1	
Residential Earth Power Loan	4.3		18.0		2.0	
Residential CSI / Financial Loan Programs Total (@ Meter)	9.7	1%	30.7	1%	6.8	21%
Commercial						
Commercial Lighting Program	70.7		254.3		-	
LED Roadway Lighting Conversion Program	5.2		35.3		n/a	
Commercial Building Envelope - Windows Program	12.6		31.8		4.2	
Commercial Building Envelope - Insulation Program	11.8		30.1		13.1	
Commercial Geothermal Program	24.3		101.6		n/a	
Commercial HVAC Program - Boilers	n/a		n/a		4.7	
Commercial HVAC Program - Chillers	-		8.4		n/a	
Commercial HVAC Program - CO2 Sensors	1.3		1.7		2.8	
Commercial HVAC Program - Water Heaters	n/a		n/a		0.7	
Commercial Custom Measures Program	5.7		21.6		2.1	
Commercial Building Optimization Program	2.9		14.4		3.7	
New Buildings Program	21.7		49.1		1.5	
Commercial Refrigeration Program	7.0		62.1		-	
Commercial Kitchen Appliance Program	2.7		2.2		1.0	
Network Energy Management Program	1.8		4.7		-	
Internal Retrofit Program	0.5		2.7		0.0	
Power Smart Shops	1.1		3.9		0.1	
Commercial Programs Total (@ Meter)	169.3	26%	624.0	26%	33.9	105%
Customer Service Initiatives / Financial Loan Programs						
Power Smart For Business PAYS Financing	0.6		2.3		0.1	
Commercial CSI / Financial Loan Programs Total (@ Meter)	0.6	0%	2.3	0%	0.1	0%
Industrial						
Performance Optimization Program	57.0		363.5		n/a	
Natural Gas Optimization Program	n/a		n/a		4.8	
Industrial Programs Total (@ Meter)	57.0	9%	363.5	15%	4.8	15%
Energy Efficiency Subtotal (@ Meter)	300.6	46%	1,202.2	49%	69.5	214%
Load Management						
Curtailable Rate Program	146.2		n/a		n/a	
Load Management Programs Total (@ Meter)	146.2	23%	n/a	0%	n/a	0%
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	7.1		61.9		1.7	
Customer Sited Load Displacement	85.9		580.6		n/a	
Load Displacement & Alt. Energy Programs Total (@ Meter)	93.0	14%	642.5	26%	1.7	5%
Conservation Rates						
Conservation Rates - Residential	16.9		140.1		n/a	
Conservation Rates - Commercial	24.3		202.1		n/a	
Conservation Rates Total	41.2	6%	342.1	14%	n/a	0%
Fuel Choice						
Fuel Choice	66.7		250.7		(38.8)	
Fuel Choice Total	66.7	10%	250.7	10%	(38.8)	(120%)
Program Impacts Total (@ Meter)	647.8	100%	2,437.5	100%	32.4	100%
Interactive Effects					(2.2)	
Codes, Standards and Regulations (@ Meter)	358.8		1,087.4		78.0	
Power Smart 2014/15 to 2028/29 Impacts (@ Meter)	1,007		3,525			
Power Smart 2014/15 to 2028/29 Impacts (@ Generation)	1,136		3,978		108	
Savings Achieved To 2013/14 (@ Meter)	442		2,043			
Savings Achieved To 2013/14 (@ Generation)	500		2,307		103	
Grand Total (@ Meter)	1,448		5,568			
Grand Total (@ Generation)	1,635		6,286		211	

2.1.2 Other Fuel Savings

Through funding from the Affordable Energy Fund, residential customers using heating sources other than natural gas and electricity are eligible to participate in the Home Insulation, Water & Energy Saver and Oil & Propane Furnace Replacement programs. The following table provides the oil and propane fuel savings estimated to be achieved through this funding.

It is estimated that savings of 399,400 litres of fuel oil and 180,700 litres of propane will be achieved from 2014/15 to 2028/29.

Affordable Energy Fund Other Fuel Savings
2014/15 - 2028/29
(000s, litres)

	2014/15	2015/16	2016/17 - 2028/29
Fuel Oil Savings			
Home Insulation Program	6.0	6.0	54.4
Water & Energy Saver Program	4.6	4.6	4.6
Oil & Propane Furnace Replacement	46.0	46.0	227.1
Annual Fuel Oil Savings	56.6	56.6	286.1
Cumulative Fuel Oil Savings, 2014/15 - 2028/29	56.6	113.3	399.4
Propane Savings			
Home Insulation Program	7.6	7.6	69.0
Water & Energy Saver Program	2.5	2.5	2.5
Oil & Propane Furnace Replacement	12.9	12.9	63.4
Annual Propane Savings	22.9	22.9	134.9
Cumulative Propane Savings, 2014/15 - 2028/29	22.9	45.9	180.7

2.1.3 Energy Efficient Codes, Standards & Regulation Savings

Many Canadian and U.S. electric utilities, including Manitoba Hydro, have been engaged in DSM activities for more than two decades. In addition to utility specific DSM programs, Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and, in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees. These codes and standards are subsequently referenced in national and provincial regulations that mandate minimum energy performance levels for a variety of appliances, buildings and other energy consuming measures. The focus of Manitoba Hydro's efforts on these committees is to advance the progress of product efficiency improvements through the development of test methodologies that facilitate measurement and comparison of energy performance and provide for minimum energy performance levels that reasonably represent performance improvements available from commercially viable product advancements, which are then incorporated into Manitoba Power Smart programs, and subsequent energy efficiency regulations and building codes proposed by national and provincial regulators.

Not all codes and standards are regulated, with some codes and standards being developed for the purpose of supporting good business practices that assist customers in quantifying and comparing the energy performance of measures being considered for implementation. In these instances, Manitoba Hydro supports the adoption of such non-regulated codes and standards within its Power Smart programs.

Manitoba Hydro annually prepares a forecast of the expected influence of both regulated and non-regulated codes and standards, and since 1995 this forecast has been used to adjust Manitoba Hydro's system load forecast.

Strategic Steering Committee on Performance, Energy Efficiency and Renewables

Manitoba Hydro is a leading contributor on the Canadian Standards Association's Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This Canadian Standards Association committee, with participation from federal and provincial authorities, electric utilities, industry associations and equipment suppliers, provides oversight and governance for the process used to develop energy performance standards and establish minimum energy performance levels for energy consuming measures across most residential, commercial and industrial sectors. SCOPEER includes Technical Committees responsible for specific end-use technology areas, including Heating, Ventilation, Air Conditioning and Refrigeration Equipment (TC 401), Industrial Equipment (TC 402), Residential Equipment (TC 403), Lighting Equipment (TC 419), Solar Equipment (TC 420) and Energy Management (TC 422). Individual Technical Subcommittees operating within each of the Technical Committees are responsible for the development of specific standards related to the energy performance of end-use measures that are vetted and approved by the SCOPEER committee for adoption. Electric utilities, equipment suppliers and consumer reference these standards within their programs and specific areas of activity, while regulatory agencies at the national and provincial level adopt these standards and their associated minimum energy performance levels into energy efficiency regulations.

Energy Savings from Codes & Standards

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the regulation of energy efficient codes and standards as such regulations ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance to ensure successful implementation.

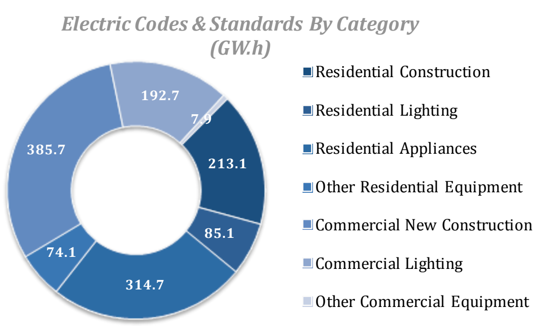
Efforts to achieve energy savings through Energy Efficient Codes and Standards initiatives are forecasted in the 2014-2017 Power Smart Plan - 15 year supplemental report to achieve capacity savings of 419 MW, energy savings of 1273 GW.h and 84 million cubic meters of natural gas annually by 2028/29. As a result of these savings, a greenhouse gas emissions reduction of 1.0 million tonnes is expected by 2028/29.

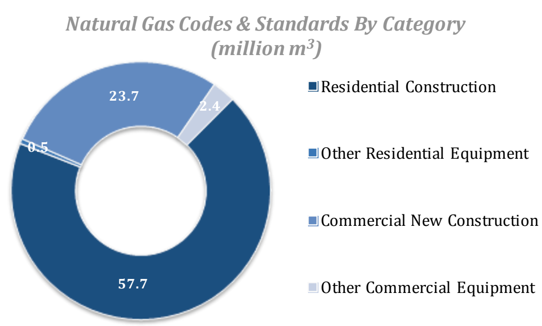
The following table and charts provide a summary of the planned energy savings in 2028/29 from codes and standards that currently implemented in energy efficiency regulation at the provincial and national level. Future DSM plans will provide updated forecasts of savings from codes and standards based on new information, such as the pending proposals being put forward by Natural Resources Canada for Amendments 13 and 14, which include both new or enhanced energy efficiency regulations for a variety of energy consuming measures.

Energy Savings from Codes & Standards
2014/15 - 2028/29

Code Category	Components	Energy and Demand Savings Winter MW	Annual GW.h	Natural Gas Annual millions m³	CO2 Reductions Annual Tonnes
Residential Construction	Insulation, Windows, Pilot Light Gas Fire Place, Furnance, Heat Recovery Ventilation, Showerhead	106.5	213.1	57.7	253,601
Residential Lighting	General Service Lamps	20.3	85.1	0.0	57,418
Residential Appliances	Dishwashers, Clothes Washers, Clothes Dryers, Refrigerators, Freezers, Ranges, Stoves, Cooktops	54.1	314.7	0.0	212,453
Other Residential Equipment	Electric Hot Water Tank, Central Air Conditioning, Residential Furnace	3.1	74.1	0.5	51,023
Commercial New Construction	Various Building Code Amendments	170.9	385.7	23.7	305,407
Commercial Lighting	General Service Lamps, Exit Signs, Fluorescent Lamp Ballasts	53.6	192.7	0.0	130,105
Other Commercial Equipment	Commercial Furnace, Boiler and Spray Valves	10.6	7.9	2.4	9,897
Total @ Generation		419	1273	84	1,019,905

** Totals per above include savings attributed to specific Power Smart programs and thus differ from Codes and Standards savings reported in Appendices A.1, A.3 and C.1*





Status of Codes and Standards

The following table summarizes the status of changes to provincially and nationally regulated codes and standards included in the 2014-2017 Power Smart Plan - 15 year supplemental report, including actual or expected dates for implementation.

For electricity, changes that account for 67% of total energy savings have been enacted and 33% are planned.

For natural gas, changes that account for 64% of total energy savings have been enacted and 36% are planned.

Status of Changes to Codes and Standards

Code Category	Components	Energy Annual GW.h	Natural Gas Annual million m^3	Level of Government	Enacted	Expected Effective Date Announced	Expected Effective Date Planned
Residential Construction	Building Code - Insulation	38.4	6.0	MB	2008		
Residential Construction	Building Code - Various measures	141.1	45.4	MB	2010		
Residential Construction	Building Code - Various measures	33.7	6.2	MB			2020
Residential Lighting	General Service Lamps (MEPS)	85.1	0.0	Federal	2014		
Residential Appliances	Various appliances	314.7	0.0	Federal			
Other Residential Equipment	Electric Hot Water Tank	15.9	0.0	Federal	2004		
Other Residential Equipment	Central Air Conditioning	58.2	0.0	Federal	2006		
Other Residential Equipment	Residential Furnace	0.0	0.5	Federal / MB	2009		
Commercial New Construction	Building Code	385.7	23.7	MB			2017
Commercial Lighting	General Service Lamps (MEPS)	33.9	0.0	Federal	2014		
Commercial Lighting	Exit Signs	1.9	0.0	Federal	2004		
Commercial Lighting	Fluorescent lamp ballasts (New / Reno)	157.0	0.0	Federal	2006 / 2010		
Other Commercial Equipment	Commercial Furnace	0.0	0.3	Federal / MB	2009		
Other Commercial Equipment	Commercial Boilers	0.0	0.2	Federal / MB		2016	
Other Commercial Equipment	Commercial Spray Valves	7.9	1.9	Federal / MB	2011		
Total (GW.h)		1273			854	0.0	419
					67%	0%	33%
Total (million m^3)			84		54	0.2	30
					64%	0%	36%

Code, Standard & Regulation Descriptions

The following section describes each of the codes and standards listed in the Summary Table noted in Section 2.1.3 that have been taken into consideration when developing a forecast for projected savings.

Residential Construction

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 4/2008
Registered: January 11, 2008
Effective date: October 1, 2008

Manitoba Hydro has been offering the Power Smart New Home program to customers across the province since 2004. The New Home program promoted and offered incentives to customers for the installation of energy efficient technologies and building practices within the New Home construction industry. Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders' Association when developing requirements for the program. Specifically, the Power Smart New Home program has required and been promoting a minimum requirement for R20 insulation in the foundation walls of new homes since 2004.

Changes to Table 9.25.5.2. (Minimum Thermal Resistance for the Building Envelope) of the Manitoba Building Code (Regulation 127/2006) came into effect on October1, 2008. The changes related to the minimum requirement for insulation R-value for the interior and exterior foundation walls of new homes. The code change increased the minimum required insulation value from R12 to R20.

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 142/2010
Registered: October 4, 2010
Effective date: December 1, 2010

Manitoba Hydro has promoted energy efficient technologies and building practices within the residential new construction segment through delivery of the Power Smart New Home Program. When developing program requirements, Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders Association.

Through the delivery of the Power Smart Gold Home offering, Manitoba Hydro planned to aid the advancement of future building code by promoting and offering incentives to customers to build their home with Power Smart recommended technologies and construction practices. The Gold standard announced in 2007 required the use of heat recovery ventilators (HRV), 94 % AFUE furnaces, electronic ignition for natural gas fireplaces, R50 attic insulation, water efficient fixtures and many other building envelope improvements.

Effective December 1st, 2010, Manitoba implemented changes to the building and plumbing codes that increased energy and water efficiencies. These changes were the result of extensive consultations by the Office of the Fire Commissioner involving new homebuilders, contractors and technical experts. The new efficiencies incorporated into new construction and homes undergoing extensive renovations included:

- specifying minimum energy-efficiency requirements for windows,
- eliminating the pilot light in gas fireplaces,
- increasing the required level of attic insulation to R50,
- requiring a minimum 94 per cent fuel-efficiency rating for furnaces,
- specifying a mid-efficient heat-recovery ventilator, and
- introducing energy-modeling software that will allow builders to model alternatives to the code requirements.
- Requiring a maximum flow rate for primary showerheads to 1.75 GPM

Through its close working relations with key industry stakeholders and the Power Smart New Home Program offering, Manitoba Hydro succeeded in advancing these changes to the Manitoba Building code. In fact, a majority of the technologies adopted by the Manitoba Building Code for the December 1, 2010 update were part of the aforementioned Power Smart Gold Home standard requirements. Without the program providing information, education, training, and incentives for these technologies and building practices, the industry would have been less likely to adopt these technologies and transform the market. The program created demand for these technologies, provided builders an opportunity to gain experience using them, and provided trades and contractors training opportunities to advance their expertise and knowledge of the technologies.

<u>Building Code</u>
Manitoba Building Code, amendment (PROVINCIAL)
Regulation (Proposed)
Effective date: 2020

Manitoba Hydro is currently assessing the Power Smart New Home program. The program will promote and offer incentives to customers for the installation of energy efficient technologies and building practices within the New Home construction industry. Manitoba Hydro will work closely with industry stakeholders with the aim to build market acceptance of Power Smart New Home technologies for ease of adoption in the Manitoba Building Code in 2020.

Residential Lighting

General Service Lamps
National Resources Canada (FEDERAL)
Amendment 12B to Energy Efficiency Regulations
Published: January 15, 2014 (Canada Gazette Part II)
Effective date(s): January 1st, 2014 - 75 to 100 watt equivalent lamps
December 31st, 2014 - 40 to 60 watt equivalent lamps

The Government of Canada announced in Amendment 12B to the Energy Efficiency Regulations, published on January 15, 2014 that they would introduce Minimum Energy Performance Standards (MEPS) for general service lamps in 2012. The consequent Regulations came into force in December 2013 and applied to 100 and 75 W bulbs manufactured on or after January 1, 2014, and to 60 and 40 W bulbs manufactured on or after December 31, 2014. The Regulations prohibit the importation and interprovincial shipment of non-compliant products. The Regulations provide for a number of alternatives to inefficient bulbs. Where no alternatives exist, exemptions are made.

Residential Appliances

Manitoba Hydro is a key player on the Canadian Standards Association's Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This committee is responsible for changes to provincial and national performance standards and legislation which have resulted in the improvement of energy utilization of numerous appliances such as dishwashers, clothes washers & dryers, refrigerators and freezers, and ranges/stoves/cooktops.

Other Residential Equipment

Hot Water Tank Standby Losses
National Resources Canada (FEDERAL)
Amendment 8 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C191-00
Published: September 22, 2004 (Canada Gazette Part II)
Effective date(s): July 1, 2004

Standby heat loss is the heat lost and energy wasted by heating water and storing it in a tank such as the case with traditional tank hot water heaters. That is, heat leaches from the tank to the surrounding air, causing the heater to heat up the water again Storage water heater models with heavily insulated tanks can significantly reduce heat loss.

In 2004, the CSA published a standard (C191-00) which specified requirements related to delivery, minimum standby performance, heater element ratings, and marking of electric storage tank water heaters. For standards, standby heat loss savings are based on the water heated for use by dishwashers and clothes washers.

Central Air Conditioning
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C656-05
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15, 2006

In November 2006, the CSA published a standard (C656-05) which specified mandatory MEPS applied to permanently installed 'air-source' air-conditioner and heat pumps. Equipment types include air conditioners and heat pumps that are single package and split system, single and three-phase, with rated capacity of less than 19 kW (65,000 Btu/h). For air conditioners, a minimum SEER rating of 13 was mandated.

Manitoba Hydro provides a fixed interest finance plan that may be used for renovations including central air, mid-efficient natural gas/electric furnaces and water heaters, direct vent natural gas fireplaces, security lights and fixtures under the Energy Finance Plan. Pre 2005, a minimum SEER rating of 10 for Air Conditioners was required for eligibility for financing under the plan. In order to comply with the forthcoming national standard, Manitoba Hydro raised the minimum SEER to 13 for eligibility of financing in October, 2005; approximately one year earlier.

<u>Residential High Efficiency Furnace</u>
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of the Federal Energy Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the heating market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the Manitoba market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making the Amendment acceptable to the industry and to consumers.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a major role in the development of the Provincial Regulation. Manitoba Hydro staff assisted the Province by providing technical and market data regarding the heating market, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making regulation acceptable to the industry.

Commercial New Construction

Building Code

The national commitment to update the 1997 National Energy Code for Buildings (NECB) was initiated in Manitoba by the Energy Code Advisory Committee (ECAC) which was led by Manitoba Hydro. Manitoba Hydro also chaired the national Building Energy Code Collaborative (BECC), which was formed in response to the recommendations provided by ECAC. As a result of the work done by BECC, formal support was provided by jurisdictions across Canada to undertake the work to update the 1997 NECB and a national working group was formed to conduct the detailed work for updating the code. Manitoba's Minister of Labour provided formal support that signaled Manitoba's intention to adopt the document once published, however the Province still moved forward with their own energy strategy and convened a sub-committee of the Building Standards Board of Manitoba to recommend Manitoba-based energy and water efficiency recommendations that could be implemented in advance of the release of the 1997 NECB.

In January 2011, the energy efficiency amendments developed for the Manitoba building code were approved by the Building Standards Board of Manitoba and the Minister of Labour. However, with the NECB already through its public consultation phase and targeting a release date of Fall 2011, it was decided to hold back on regulating the specific Manitoba amendments so that a review and implementation of the NECB could be implemented. The sub-committee that developed the Manitoba amendments was reconvened in fall of 2012 with the task of reviewing the NECB and determining its applicability to the Manitoba market. Once again, Manitoba Hydro played a key role with several Power Smart staff contributing to this process. The sub-committee provided a recommendation that was formally adopted with minor adjustments in the December of 2013 for implementation and enforcement in December of 2014.

Manitoba Hydro staff continues to contribute to the national process for the development of the 2015 edition of the NECB and several Customer Engineering Services staff members formally attend regular code development meetings to ensure Manitoba Hydro objectives are met. Manitoba Hydro staff are also members of the Manitoba Building Standards Board Sub-Committee on Energy and Water Efficiency, which is responsible for recommending that the Province adopt the 2011 NECB and creation of additional recommendations specific to Manitoba that will be incorporated as amendments.

Commercial Lighting

Since 1992, Manitoba Hydro has been actively promoting energy efficient lighting technologies for commercial applications. Activities involved in developing lighting standards include:

- Collaboration with other utilities, identify necessary research
- Work with Canadian Electrical Association
- Liaise with manufacturers to encourage the development and improvement of energy efficient lighting
- Product testing
- Liaise with National Research Council
- Participation on the CSA Standards Setting Committee
- Participation on the Canadian Lighting Industry Collaborative

<u>General Service Lamps</u>
National Resources Canada (FEDERAL)
Amendment 12B to Energy Efficiency Regulations
Published: January 15, 2014 (Canada Gazette Part II)
Effective date(s): January 1st, 2014 - 75 to 100 watt equivalent lamps
December 31st, 2014 - 40 to 60 watt equivalent lamps

The Government of Canada announced in Amendment 12B to the Energy Efficiency Regulations, published on January 15, 2014 that they would introduce Minimum Energy Performance Standards (MEPS) for general service lamps in 2012. The consequent Regulations came into force in December 2013 and applied to 100 and 75 W bulbs manufactured on or after January 1, 2014, and to 60 and 40 W bulbs manufactured on or after December 31, 2014. The Regulations prohibit the importation and interprovincial shipment of non-compliant products. The Regulations provide for a number of alternatives to inefficient bulbs. Where no alternatives exist, exemptions are made.

<u>Exit Signs</u>
National Resources Canada (FEDERAL)
Amendment 8 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C860-01
Published: September 22, 2004 (Canada Gazette Part II)
Effective date: November 1, 2004

In September of 2004, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for internally lighted exit signs with the publication of Amendment 8 in Canada Gazette Part II. This standard contains voluntary minimum performance standards of 22 watts for signs 120 V or less, and 27 watts for signs greater than 120 V. These levels were harmonized with the National Building Code of Canada. The standard also addresses the visibility performance of the exit sign. To meet these standards, typically requires that LED technology be employed. In the area of LED lighting, the program supported these minimum efficiency levels for new exit signs with signs set at a level that only LED exit signs could meet.

<u>Fluorescent lamp ballasts</u>
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C654-M91
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15th, 2006 (New Construction Market)
April 1st, 2010 (Renovation Market)

In November of 2006, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for florescent lamp ballasts with the publication of Amendment 9 in Canada Gazette Part II. Manitoba Hydro's lighting initiative helped support this Federal code change that required fluorescent lamp ballasts meet a prescribed minimum energy performance standard in the new construction market in 2006 and the renovation market in 2010.

Other Commercial Equipment

<u>Commercial High Efficiency Furnace</u>
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of Canada's Energy Efficiency Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the furnace market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart programs such as the Power Smart Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all influenced market adoption; increasing market penetration of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's involvement has expedited market transformation and thus facilitated the adoption of the federal efficiency regulation.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a material role in the development of the provincial efficiency regulation. Manitoba Hydro staff assisted the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart programs such as the Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all helped to expedite market adoption of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's active involvement had expedited market transformation, and thus facilitated the adoption of the provincial efficiency regulation.

<u>Commercial Boilers</u>
National Resources Canada (FEDERAL)
Bulletin published: August 2010
Test Standard: HI BTS 2000, Rev 06.07 Method to Determine Efficiency of Commercial Space Heating Boilers
Proposed Effective date(s): March, 2015 (90% Min Efficiency Rating - New Construction Market)
March, 2015 (85% Min Efficiency Rating - Existing Buildings Market)

In August of 2010, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) Natural Resources Canada (NRCan) proposed to amend Canada's ENERGY EFFICIENCY REGULATIONS (the Regulations) to require dealers to comply with minimum energy performance standards (MEPS) for commercial gas and oil-fired boilers, imported or shipped inter-provincially, for sale or lease in Canada. NRCan proposes that commercial packaged boilers meet minimum efficiency ratings of 90% for the New Construction mark and 85% for the Replacement Market, effective March, 2015.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to new Manitoba buildings. By April 1 2013, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This regulation is equivalent to the proposed federal regulation, but will be enacted two years earlier.

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 72% by April 2013, thus facilitating the adoption of a provincial performance standard two years earlier than the rest of Canada.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to existing Manitoba buildings. By March 2015, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This is approximately 5% higher than the proposed federal regulation requiring all boilers sold to be at least 85% efficient (near-condensing).

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 75% by March 2015, thus facilitating the adoption of a higher performance standard in Manitoba.

<u>Commercial Pre Rinse Spray Valve</u>
Manitoba Plumbing Code
Regulation 32/2011
Adoption of National Plumbing Code of Canada 2010
Published: March 28, 2011 The Buildings and Mobile Homes Act (C.C.S.M. c. B93)
Effective date: April 1, 2011

On April 1, 2011 the Manitoba Government repealed the Manitoba Plumbing Code, Manitoba Regulation 128/2006 and adopted the National Plumbing Code of Canada 2010 issued by the Canadian Commission on Buildings and Fire Codes, National Research Council Canada. The code states that the maximum flow rate for a pre-rinse spray valve not exceed 6.1 litres per minute (1.60 gallons per minute). The Power Smart Rinse & Save Program influenced market adoption; converting the Manitoba market to pre-rinse spray valves with equal or higher energy efficiency than the code. Manitoba Hydro's involvement has expedited market transformation and thus facilitated the adoption of the code.

At an Industrial level, Manitoba Hydro undertakes codes and standards development work with the following organizations:

- Natural Resources Canada (NRCAN)
- Province of Manitoba
- Canadian Standards Association (CSA), including BC Hydro, Hydro Quebec, Ontario Power Authority, Ontario Ministry of Energy, etc)
- Centre for Energy Advancement through Technological Innovation (CEATI)
- US Department of Energy (DOE)
- Institute of Electronic and Electrical Engineers (IEEE)
- International Electrotechnical Commission (IEC)
- American Council for an Energy-Efficient Economy (ACEEE)
- Electric Power Research Institute (EPRI)
- Energy Solutions Center (ESC)
- American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE)
- Canadian Gas Association (CGA)

This work pertains primarily to industrial and commercial equipment that incorporates or applies to electric motors, variable speed drives, air compressors, compressed air systems, fans, pumps, transformers, power quality systems, battery charges, uninterruptible power supplies, lighting systems, refrigeration, heating, ventilation and air conditioning systems, and building envelope incorporating both natural gas and electric supply.

Areas of involvement include, test methods for determination of energy efficiency, performance standards, application guides for efficiency test methods and performance standards and repair standards (to maintain efficiency). Industrial codes and standards are often developed as non-regulated mechanisms designed to support good practices in the selection, operation and maintenance of energy consuming measures. As such, these codes and standards are incorporated into Manitoba Hydro's Industrial Power Smart programs supporting the savings objectives of these programs.

2.2 DSM Utility Investment

2.2.1 Internal Sources

The following table provides the cumulative electric and natural gas internal DSM investment totals to 2028/29 broken down by market sector and cost basis. Including other internal DSM investments, it is expected that by 2028/29, an additional cumulative investment amount of $978 million dollars will have been spent on Power Smart programs and initiatives. Including investments to date, it is expected that by 2028/29, a cumulative investment of achieving the energy savings will have been $1.6 billion dollars.

Internal DSM Utility Investment
2014/15 - 2028/29

	Electric Cumulative Utility Costs (Millions 2014$)		Natural Gas Cumulative Utility Costs (Millions 2014$)		Total Cumulative Utility Costs (Millions 2014$)		
Residential							
New Home Program	$2.3		$0.1		$2.4		
Home Insulation Program	$16.6		$15.4		$32.0		
Water and Energy Saver Program	$5.0		$3.2		$8.2		
Affordable Energy Program							
Affordable Energy Program - Insulation	$16.7		$35.6		$52.4		**
Affordable Energy Program - Furnace	n/a		$19.3		$19.3		**
Affordable Energy Program - Total	$16.7		$54.9		$71.7		**
Refrigerator Retirement Program	$6.6		$0.0		$6.6		
Residential LED Lighting Program	$1.9		$0.0		$1.9		
Community Geothermal Program	$21.1		$0.0		$21.1		
Opower (Behavioral)	$0.0		$0.0		$0.0		
Residential Programs Total	$70.1	10%	$73.7	61%	$143.8	17%	
Commercial							
Commercial Lighting Program	$92.3		$0.0		$92.3		
LED Roadway Lighting Conversion Program	$40.4		$0.0		$40.4		
Commercial Building Envelope - Windows Program	$11.8		$6.7		$18.5		
Commercial Building Envelope - Insulation Program	$12.6		$20.9		$33.5		
Commercial Geothermal Program	$47.6		$0.0		$47.6		
Commercial HVAC Program - Boilers	n/a		$2.4		$2.4		
Commercial HVAC Program - Chillers	$2.0		$0.0		$2.0		
Commercial HVAC Program - CO2 Sensors	$0.5		$1.9		$2.4		
Commercial HVAC Program - Water Heaters	n/a		$0.9		$0.9		
Commercial Custom Measures Program	$10.1		$3.2		$13.3		
Commercial Building Optimization Program	$4.2		$4.4		$8.6		
New Buildings Program	$17.2		$3.7		$20.9		
Commercial Refrigeration Program	$8.8		$0.0		$8.8		
Commercial Kitchen Appliance Program	$0.2		$0.5		$0.7		
Network Energy Management Program	$0.7		$0.0		$0.7		
Internal Retrofit Program	$2.5		$0.1		$2.6		
Power Smart Shops	$1.5		$0.1		$1.7		
Commercial Programs Total	$252.5	34%	$44.7	37%	$297.2	35%	
Industrial							
Performance Optimization Program	$143.4		n/a		$143.4		
Natural Gas Optimization Program	n/a		$2.3		$2.3		
Industrial Programs Total	$143.4	20%	$2.3	2%	$145.7	17%	
Energy Efficiency Subtotal	$466.1	64%	$120.7	99%	$586.7	69%	
Load Management							
Curtailable Rate Program	$89.3		n/a		$89.3		
Load Management Programs Total	$89.3	12%	n/a	0%	$89.3	10%	
Load Displacement & Alternative Energy							
Bioenergy Optimization Program	$10.2		$0.8		$11.0		
Customer Sited Load Displacement	$84.3		n/a		$84.3		
Load Displacement & Alt. Energy Programs Total	$94.5	13%	$0.8	1%	$95.4	11%	
Conservation Rates							
Conservation Rates - Residential	$15.6		n/a		$15.6		
Conservation Rates - Commercial	$18.4		n/a		$18.4		
Conservation Rates Total	$34.1	5%	n/a	0%	$34.1	4%	
Fuel Choice							
Fuel Choice	$49.4		$0.0		$49.4		
Fuel Choice Total	$49.4	7%	$0.0	0%	$49.4	6%	
Program Impacts Total	$733.3	100%	$121.5	100%	$854.8	100%	
Program Support and Contingency Costs	$87.2		$34.3		$121.4		
Power Smart Investment Total, 2014/15 - 2028/29	$820.5		$155.8		$976.2		
Other Internal DSM Investments							
Afforedable Energy Fund	$1.1		$0.7		$1.8		
Cumulative Investment Total, 2014/15 - 2028/29	$821.5		$156.5		$978.0		
Spent to 2013/14	$461.0		$123.6		$584.6		
Cumulative Investment Total, 1989/90 - 2028/29	$1,282.5		$280.1		$1,562.6		

*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*

The following table outlines the total projected DSM budget including all internal sources of funding to 2028/29. A total investment of $978 million is planned for the period of 2014/15 to 2028/29.

Forecasted Internal DSM Budget
2014/15 - 2028/29
(Millions 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Electric DSM																
Electric Power Smart	52.3	58.5	74.0	79.4	86.8	71.3	64.9	53.6	43.4	42.2	39.7	39.6	38.0	37.2	37.3	818.2
Affordable Energy Fund	1.4	1.1	0.4	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0
Annual Electric Budget	$53.6	$59.6	$74.4	$79.4	$86.9	$71.3	$64.9	$53.6	$43.4	$42.2	$39.7	$39.6	$38.0	$37.2	$37.3	$821.3
Natural Gas DSM																
Natural Gas Power Smart	10.2	10.8	11.2	9.5	8.7	8.7	8.6	8.7	8.8	8.9	8.6	8.6	8.5	5.1	5.0	129.9
Affordable Energy Fund	3.3	3.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2
Furnace Replacement Budget	2.6	2.7	2.7	2.6	2.4	2.3	1.9	1.2	0.7	0.2	0.1	0.1	0.1	0.0	0.0	19.3
Annual Natural Gas Budget	$16.1	$16.4	$14.8	$12.1	$11.1	$11.1	$10.5	$9.9	$9.5	$9.1	$8.6	$8.6	$8.6	$5.1	$5.0	$156.5
Oil and Propane DSM																
Affordable Energy Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Annual Oil and Propane Budget	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3
Manitoba Hydro Annual Budget	$69.7	$76.1	$89.2	$91.5	$98.0	$82.4	$75.4	$63.5	$52.8	$51.4	$48.4	$48.3	$46.6	$42.3	$42.4	
Cumulative Investment 2014/15 - 2028/29	$69.7	$145.8	$235.0	$326.5	$424.5	$506.9	$582.3	$645.9	$698.7	$750.1	$798.4	$846.7	$893.3	$935.7	$978.0	$978.0

Note: Figures may not add due to rounding

Including investments to date, it is expected that by 2028/29, a cumulative investment of achieving the energy savings will have been $1.6 billion dollars, $1.3 billion of the costs are funded through the Corporation's Power Smart electricity budget, $232 million from the Power Smart natural gas budget, $37 million from the Affordable Energy Fund, and $27 million from the Furnace Replacement budget for targeting furnace replacement.

Total Internal DSM Budget
1989/90 - 2028/29
(Millions 2014 $)

	Expenditures to date 1989/90 - 2013/14	15 yr planning horizon 2014/15 - 2028/29	Total 1989/90 - 2028/29
Electric DSM			
Electric Power Smart	448.7	818.2	1,267.0
Affordable Energy Fund	11.8	3.0	14.8
Annual Electric Budget	$460.5	$821.3	$1,281.8
Natural Gas DSM			
Natural Gas Power Smart	102.1	129.9	232.0
Affordable Energy Fund	13.7	7.2	20.9
Furnace Replacement Budget	7.8	19.3	27.1
Annual Natural Gas Budget	$123.6	$156.5	$280.1
Oil and Propane DSM			
Affordable Energy Fund	0.5	0.3	0.7
Annual Oil and Propane Budget	$0.5	$0.3	$0.7
Cumulative Investment 1989/90 - 2028/29	$584.6	$978.0	$1,562.6

Note: Figures may not add due to rounding

Affordable Energy Fund

The Affordable Energy Fund is an internal fund established as a result of the Winter Heating Cost Control Act. The purpose of the Fund is to provide support for programs and services that achieve specific objectives outlined under the Act including encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, low income customers and seniors and encouraging the use of alternative energy sources such as renewable energy.

Manitoba Hydro established the Affordable Energy Fund following the passing of the Winter Heating Cost Control Act on November 20, 2006 in the Manitoba Legislature. The Affordable Energy Fund supports Manitoba Hydro's sustainable development initiatives.

The following projects and associated funding levels have been approved for support by the Affordable Energy Fund. As of March 31st, 2013 approximately $26.8 million of the Affordable Energy Fund had been spent, leaving the remaining $11.2 million.

Affordable Energy Fund Budget
(Millions $)

	Total Budget	Expeditures to Date	Remaining Total Budget
Affordable Energy Program	23.9	15.2	8.7
Geothermal Support	1.6	1.4	0.2
Community Support and Outreach	0.8	0.7	0.1
Oil and Propane Heated Homes	0.3	0.3	0.0
Special Projects			
Residential ecoENERGY Audits	0.5	0.5	0.0
Oil and Propane Furnace Replacement	0.2	0.1	0.0
Solar Water Heaters	0.3	0.3	0.0
Power Smart Residential Load	2.5	1.8	0.6
Oil and Propane Heated Homes - Additional funding	0.3	0.0	0.3
Spruce Wood Loggers	0.2	0.0	0.2
Community Energy Development			
ecoENERGYProgram Funding	4.1	4.1	0.0
Power Smart PAYS Financing Program	0.4	0.0	0.4
Subtotal	$35.0	$24.5	$10.5
Energy & Resource Fund *	0.8	0.8	0.0
Manitoba Electric Bus *	1.2	0.9	0.3
FortWhyte EcoVillage *	0.1	0.1	0.0
Diesel Community Green Pilot Demonstration *	0.4	0.0	0.4
Métis Generation Fund *	0.5	0.5	0.0
TOTALS	$38.0	$26.8	$11.2

Note: Non Demand Side Management Budget*
Figures may not add due to rounding

The following table identifies the programs and associated funding levels that the Affordable Energy Fund will support over the Power Smart Planning horizon.

Affordable Energy Fund Budget
(Millions 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25 - 2028/29	Total
Affordable Energy Program	4.0	3.7	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7
Geothermal Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Community Support and Outreach	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Oil and Propane Heated Homes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Special Projects												0.0
Residential ecoENERGY Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Smart Residential Load	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Oil and Propane Heated Homes - Additional funding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Spruce Wood Loggers	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Community Energy Development												
ecoENERGYProgram Funding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power Smart PAYS Financing Program	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Subtotal	$4.7	$4.1	$1.3	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$10.5
Energy & Resource Fund *	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Manitoba Electric Bus *	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
FortWhyte EcoVillage *	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Community Green Pilot Demonstration *	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Métis Generation Fund *	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Budget	5.3	4.1	1.3	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	11.2
Cumulative Budget, 2014/15 - 2028/29	$5.3	$9.4	$10.7	$10.8	$10.9	$11.0	$11.0	$11.1	$11.1	$11.1	$11.2	$11.2

Note: Annual interest accruals are not included in the above forecast
Figures may not add due to rounding

Affordable Energy Program

The Affordable Energy Fund supports the Affordable Energy Program by targeting low-income Manitobans through an individual, community and neighbourhood approach.

Geothermal Support

The Affordable Energy Fund provides funding to support the application of geothermal technology. A portion of the fund is being used to subsidize the interest rate for Residential Earth Power Loan program participants from 6.5% to 4.9% for the first five years of the loan term.

Community Support and Outreach

The Affordable Energy Fund provides funding for additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives.

Oil and Propane-Heated Homes

The Affordable Energy Fund provides incentives to allow customers with wood, oil or propane heating to participate in Power Smart programs. The estimated savings of the other fuel types resulting from the installation of insulation in customer homes are provided in the next section of this report. (Note: Additional funding provided through the special projects category)

Special Projects

Residential Energy Assessment Service (ecoENERGY Audits)

The Affordable Energy Fund contributes the incremental costs associated with providing Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

Oil & Propane Furnace Replacement

Manitoba Hydro extended the eligibility for the Power Smart Furnace Replacement Program to those customers upgrading an oil or propane furnace to a high efficiency electric or natural gas furnace.

Residential Solar Water Heating Program

Manitoba Hydro is partnering with Natural Resources Canada to deliver a residential solar water heating initiative in Manitoba. This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

Power Smart Residential Loan

The Affordable Energy Fund provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost recovery rate of 5.5% to a rate of 3.9%.

Oil and Propane-Heated Homes – Additional Funding

This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas. As this additional funding is coming from a separate Affordable Energy Fund category than the original funding, it is tracked separately.

Spruce Wood Loggers

This initiative provides funding to support Spruce Wood Loggers in upgrading their operations to include pelletizing ground wood and waste sawdust material. The pellets would provide an alternative fuel for coal-fired boilers and potentially prevent some customers in close proximity to Spruce Wood Loggers from converting to electric boilers.

Community Energy Development

ecoENERGY Program Funding – Additional Funding

Additional funding has been allocated to support the cost of offering audits in Manitoba, involving a $100 subsidy for each audit plus the incremental cost of offering audits in rural and northern Manitoba.

Power Smart PAYS Financing Program

This initiative provides funding to reduce the interest rate for the PAYS financing program from the cost recovery rate to a rate of 3.9%.

Energy and Resource Fund

The Affordable Energy Fund provided funding to the Energy and Resource Fund. Managed by the First Peoples Economic Growth Fund, this joint initiative between the Government of Manitoba and the Assembly of Manitoba Chiefs was created to maximize First Nations participation in Major Energy and Resource Projects.

Manitoba Electric Bus

Funding is provided to support the Manitoba Electric Bus Project; a joint initiative among the Province of Manitoba, Manitoba Hydro, Red River College, New Flyer Industries and

Mitsubishi Heavy Industries. The objective of the project is to develop a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

FortWhyte EcoVillage
The Affordable Energy Fund supported the research and design of a world-class ecovillage on land belonging to FortWhyte Alive.

Diesel Community Green Pilot Demonstration
This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

Métis Generation Fund for Resource & Energy Development
The Affordable Energy Fund is providing funding to the Métis Generation fund, managed by the Métis Economic Development Organization. This fund was created to enable Metis-owned businesses in Manitoba to invest in business growth and development within the resource and energy sectors in Manitoba.

Furnace Replacement Budget

The Furnace Replacement budget is an internal allocation established as a result of Public Utility Board Order 99/07. The purpose of the allocation is to establish and administer a Furnace Replacement Program for low income customers.

The following table outlines the planned additions and expenditures over the planning horizon.

Furnace Replacement Budget
(Millions 2014$)

		2014/15	2015/16	2016/17	2017/18 - 2028/29	Total
Furance Replacement Budget						
Opening Balance	18.2					
Annual Additions		3.8	3.8	0.0	0.0	25.8
Annual Budget		2.6	2.7	2.7	11.4	19.3
Annual Balance	$18.2	$19.4	$20.5	$17.8	$6.4	$6.4

Note: Figures may not add due to rounding

2.2.2 External Sources

Manitoba Hydro's Power Smart programs are supported by funding from external organizations as outlined in the following table.

The Affordable Energy Program includes partnership funding from the Provincial Government. This external funding is expected to total $2.5 million over the period of 2014/15 to 2028/29.

External Funding Budget
2014/15 - 2028/29
(Millions 2014 $)

	2014/15	2015/16	2016/17	2017/18-2028/29	Total
External Funding					
Affordable Energy Program	0.5	0.4	0.3	1.2	2.5
Cumulative Budget, 2014/15 - 2028/29	$0.5	$1.0	$1.3	$2.5	$2.5

Note: Figures may not add due to rounding

2.3 DSM Metrics and other related measurements

2.3.1 Integrated Perspective

Metrics

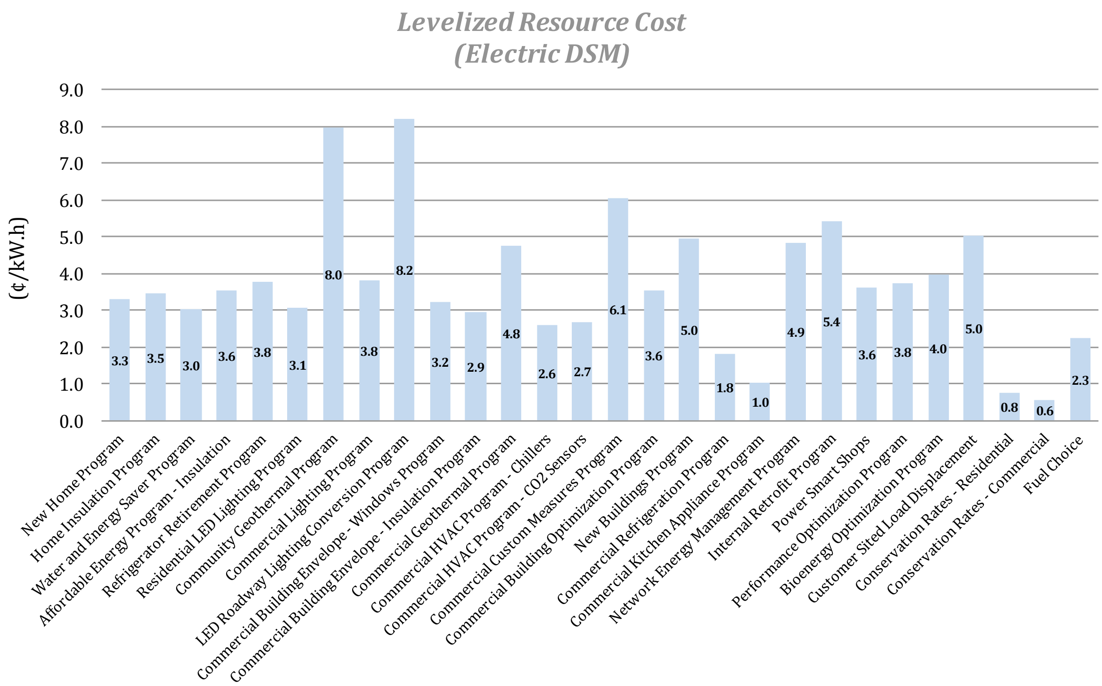
The following table outlines the cost effectiveness, from an integrated perspective, of the program offerings provided in the 2014-2017 Power Smart Plan - 15 year supplemental report.

Integrated DSM Metrics
2014/15 - 2028/29

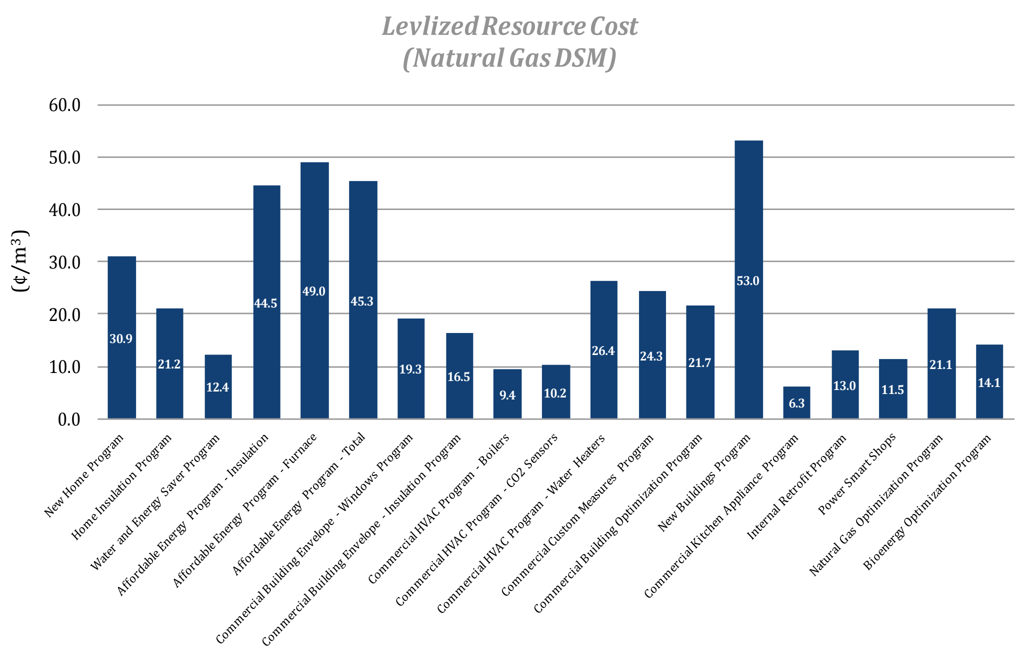
	Combined DSM		Electric DSM				Natural Gas DSM			
	SC	TRC	SC	TRC	TRC NPV	LRC (¢/kW.h)	SC	TRC	TRC NPV	LRC (¢/m³)
Residential										
New Home Program	2.1	1.9	3.6	3.3	$51.2	3.3	1.1	1.0	($1.0)	30.9 *w c*
Home Insulation Program	2.7	2.4	4.3	3.9	$40.7	3.5	1.5	1.4	$7.0	21.2
Water and Energy Saver Program	5.3	5.1	4.4	4.1	$13.5	3.0	6.7	6.5	$16.2	12.4 *w*
Affordable Energy Program										
Affordable Energy Program - Insulation	1.9	1.7	4.1	3.8	$36.4	3.6	0.8	0.8	($7.0)	44.5 ** *w*
Affordable Energy Program - Furnace	0.6	0.5	n/a	n/a	n/a	n/a	0.6	0.5	($3.3)	49.0 **
Affordable Energy Program - Total	1.7	1.5	4.1	3.8	$36.4	3.6	0.8	0.7	($10.2)	45.3 ** *w*
Refrigerator Retirement Program	1.2	1.1	1.7	1.6	$5.8	3.8	0.0	0.0	($4.7)	0.0 *i*
Residential LED Lighting Program	2.1	1.9	3.0	2.7	$3.8	3.1	0.0	0.0	($1.7)	0.0 *i*
Community Geothermal Program	1.3	1.2	1.3	1.2	$9.3	8.0	0.0	0.0	$0.0	0.0
Residential Programs Total	2.0	1.8	2.6	2.3	$160.7	4.6	1.1	1.1	$5.5	32.8
Commercial										
Commercial Lighting Program	2.6	2.4	2.7	2.4	$156.2	3.8	0.0	0.0	($5.5)	0.0 *i*
LED Roadway Lighting Conversion Program	1.3	1.2	1.3	1.2	$6.1	8.2	n/a	n/a	n/a	n/a
Commercial Building Envelope - Windows Program	3.0	2.7	3.9	3.5	$27.2	3.2	1.6	1.5	$3.6	19.3
Commercial Building Envelope - Insulation Program	2.7	2.4	4.2	3.8	$26.7	2.9	1.9	1.7	$14.4	16.5
Commercial Geothermal Program	2.2	2.0	2.2	2.0	$44.6	4.8	n/a	n/a	n/a	n/a
Commercial HVAC Program - Boilers	3.3	3.0	n/a	n/a	n/a	n/a	3.3	3.0	$9.4	9.4 *c*
Commercial HVAC Program - Chillers	2.1	1.9	2.1	1.9	$2.7	2.6	n/a	n/a	n/a	n/a
Commercial HVAC Program - CO2 Sensors	3.5	3.2	6.6	6.0	$1.9	2.7	2.9	2.7	$3.5	10.2
Commercial HVAC Program - Water Heaters	1.2	1.0	n/a	n/a	n/a	n/a	1.2	1.0	$0.1	26.4
Commercial Custom Measures Program	1.7	1.5	1.8	1.6	$7.6	6.1	1.3	1.2	$0.9	24.3
Commercial Building Optimization Program	1.9	1.8	2.6	2.4	$5.0	3.6	1.4	1.3	$1.4	21.7
New Buildings Program	2.2	2.0	2.7	2.5	$60.8	5.0	0.6	0.5	($5.9)	53.0
Commercial Refrigeration Program	4.4	4.0	4.0	3.7	$30.9	1.8	0.0	0.0	$3.6	0.0 *i*
Commercial Kitchen Appliance Program	19.3	18.4	31.2	29.2	$9.2	1.0	14.0	13.5	$9.2	6.3 *w*
Network Energy Management Program	2.3	2.1	2.4	2.2	$4.0	4.9	0.0	0.0	($0.3)	0.0 *i*
Internal Retrofit Program	1.3	1.2	1.3	1.2	$0.4	5.4	2.3	2.0	($0.1)	13.0
Power Smart Shops	2.9	2.6	2.9	2.6	$2.5	3.6	2.8	2.5	($0.1)	11.5
Commercial Programs Total	2.4	2.2	2.6	2.3	$386.0	4.2	1.7	1.6	$34.1	19.2
Industrial										
Performance Optimization Program	2.3	2.1	2.3	2.1	$156.7	3.8	n/a	n/a	n/a	n/a
Natural Gas Optimization Program	1.3	1.2	n/a	n/a	n/a	n/a	1.3	1.2	$2.0	21.1
Industrial Programs Total	2.3	2.0	2.3	2.1	$156.7	3.8	1.3	1.2	$2.0	21.1
Energy Efficiency Subtotal	2.2	2.0	2.5	2.3	$703.4	4.1	1.4	1.3	$41.6	25.4
Load Management										
Curtailable Rate Program	737.4	535.3	n/a	n/a	$32.2	n/a	n/a	n/a	n/a	n/a
Load Management Programs Total	737.4	535.3	n/a	n/a	$32.2	n/a	n/a	n/a	n/a	n/a
Load Displacement & Alternative Energy										
Bioenergy Optimization Program	1.8	1.7	1.8	1.7	$17.6	4.0	2.0	1.8	$2.2	14.1
Customer Sited Load Displacement	1.5	1.4	1.5	1.4	$156.8	5.0	n/a	n/a	n/a	n/a
Load Displacement & Alt. Energy Programs Total	1.6	1.4	1.6	1.4	$174.4	5.0	2.0	1.8	$2.2	14.1
Conservation Rates										
Conservation Rates - Residential	10.2	9.3	10.2	9.3	$104.4	0.8	n/a	n/a	n/a	n/a
Conservation Rates - Commercial	13.8	12.5	13.8	12.5	$163.1	0.6	n/a	n/a	n/a	n/a
Conservation Rates Total	12.1	11.0	12.1	11.0	$267.4	0.7	n/a	n/a	n/a	n/a
Fuel Choice										
Fuel Choice	4.7	4.3	4.7	4.3	$219.0	2.3	0.0	0.0	$0.0	0.0
Fuel Choice Total	4.7	4.3	4.7	4.3	$219.0	2.3	0.0	0.0	$0.0	0.0
Program Impacts Total	2.4	2.2	2.5	2.3	$1,396.5	3.7	1.4	1.3	$43.7	25.0
Program Support and Contingency Costs	-	-	-	-	($59.9)	-	-	-	($25.4)	-
Program Impacts Total (Incl. Support and Contingency Costs)	2.2	2.0	2.4	2.2	$1,336.6	3.9	1.2	1.1	$18.3	29.0
Other Internal DSM Investments										
Affordable Energy Fund	-	-	-	-	($0.9)	-	-	-	($0.7)	-
Overall Portfolio Metric	2.2	2.0	2.4	2.2	$1,335.7	3.9	1.2	1.1	$17.6	29.1

Notes:
*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*
AEP Electric - Total:
Excluding AEF costs, SC is 5.8, TRC is 5.3, TRC NPV is $40.1M, and LRC is 2.5 ¢/kW.h
AEP Natural Gas - Total:
Excluding AEF costs, without Furnace Replacement Program, SC is 1.1, TRC is 1.0, TRC NPV is $0.16M, and LRC is 33.4 ¢/kW.h
c Program assumption includes savings from Codes & Standards
i Program reflects natural gas interactive effects
w SC, TRC and TRC NPV include Water Savings Benefits
1) Overall portfolio metrics do not include Customer Service Initiatives / Financial Loan Programs
2) Overall portfolio LRC metric does not include Curtailable Rate Program
3) Overall portfolio metrics include all support, contingency and Affordable Energy Fund Expenditures and Furance Replacement Program

The following chart provides the Levelized Resource Cost of the electric program offerings in the 2014-2017 Power Smart Plan - 15 year supplemental report.



The following chart provides the Levelized Resource Cost of the natural gas program offerings in the 2014-2017 Power Smart Plan - 15 year supplemental report.

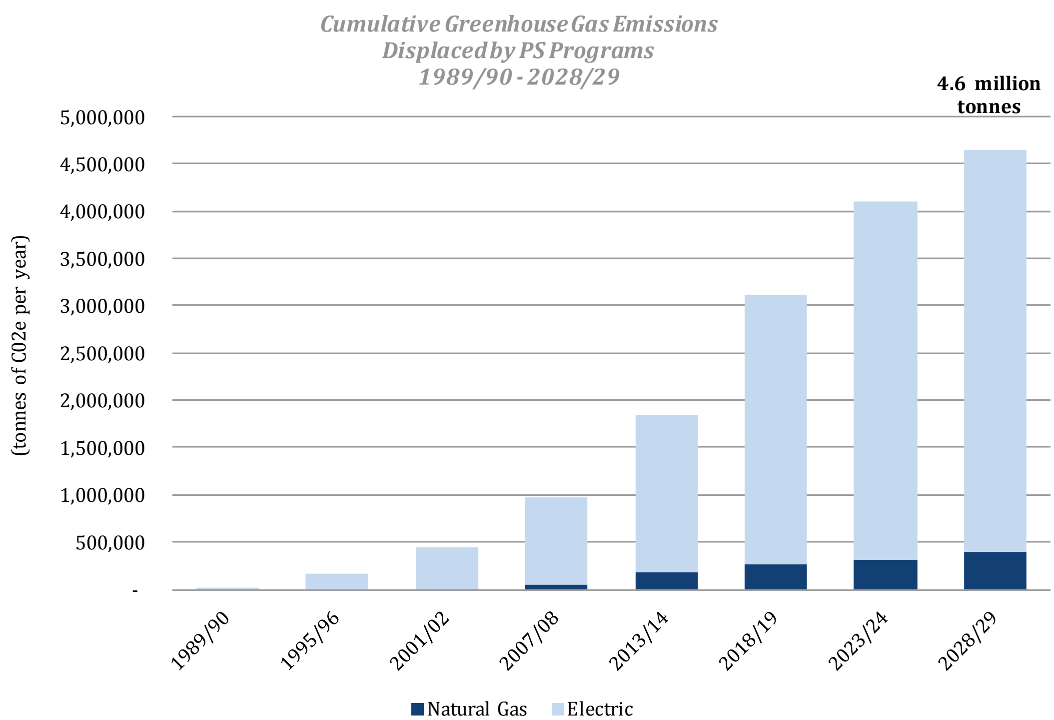


Global Greenhouse Gas Emissions Reductions

The following chart and graph depict the aggregate global greenhouse gas emissions reductions resulting from the electricity and natural gas DSM programs outlined in the 2014-2017 Power Smart Plan - 15 year supplemental report, including greenhouse gas emission reductions resulting from Manitoba Hydro's Power Smart efforts since 1989. Global greenhouse gas emission reductions of 2.9 million tonnes are forecast to be achieved due to energy savings outlined in the Power Smart Plan.

	Annual CO_2 Reductions (tonnes)
CO_2 Reductions - Electric	2,685,291
CO_2 Reductions - Natural Gas	205,900
2014/15 Power Smart Plan (2014/15 - 2028/29)	2,891,191
CO_2 Reductions Achieved to Date - Electric	1,557,430
CO_2 Reductions Achieved To Date - Natural Gas	195,193
Savings Achieved to 2013/14 (1989/90 - 2028/29)	1,752,623
Total Projected to 2028/29	4,643,814

Including reductions achieved to date, approximately 4.6 million tonnes are forecast to be realized due to Manitoba Hydro's Power Smart efforts by 2028/29.

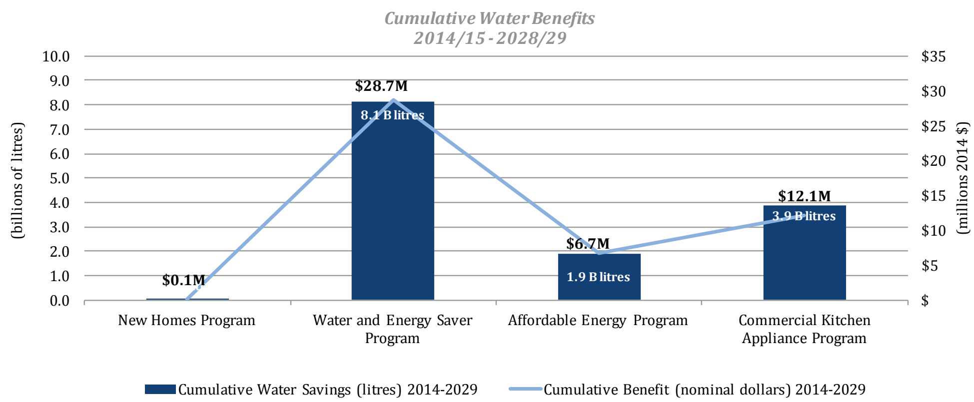


Additional Measureable Non-Energy Benefits

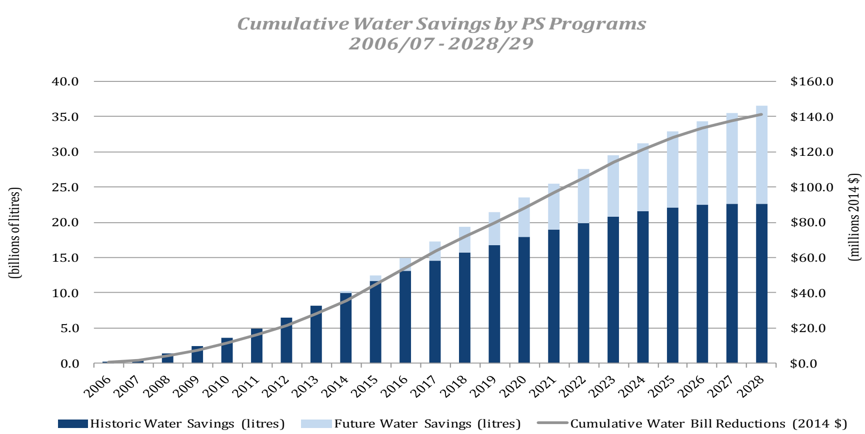
As part of the 2014-2017 Power Smart Plan - 15 year supplemental report, the following residential and commercial programs are expected to capture additional water saving benefits:

- New Homes Program
- Water and Energy Saver Program
- Affordable Energy Program
- Commercial Kitchen Appliance Program

The following graph depicts cumulative water savings in litres and cumulative customer dollar savings from each of the above programs. It is estimated that savings of approximately 14 billion liters of water and $48 million in bill savings will be achieved from 2014/15 to 2028/29.



When combined with savings to date, Power Smart programs are expected to save approximately 37 billion liters of water and $141 million by 2028/29.



2.3.2 Utility Perspective

Metrics

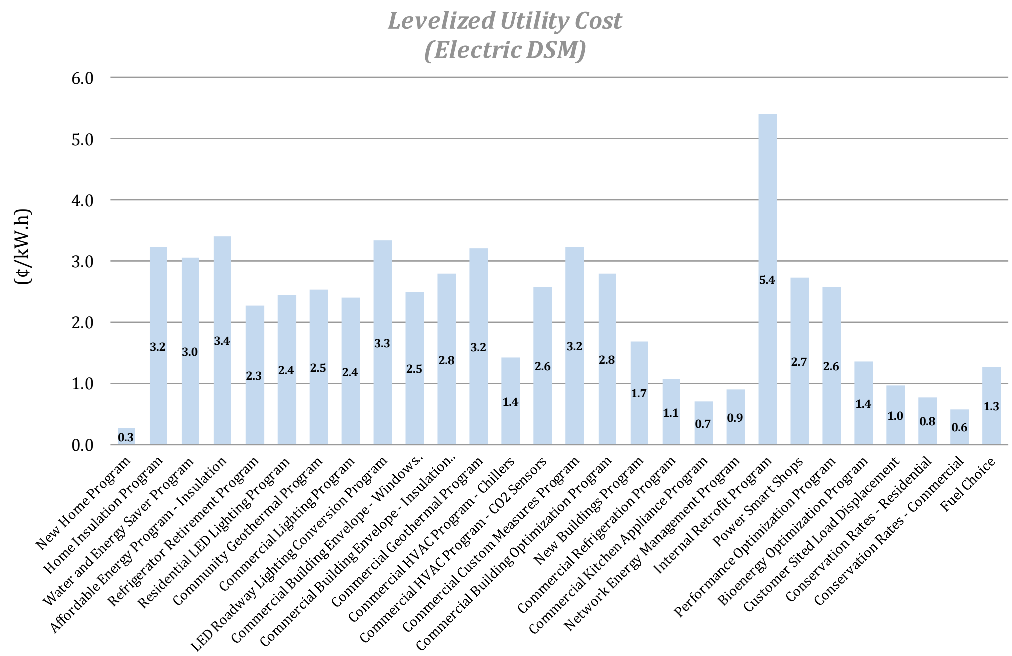
The following table outlines the cost effectiveness, from a utility perspective, of the program offerings provided in the 2014-2017 Power Smart Plan - 15 year supplemental report.

Utility DSM Metrics
2014/15 - 2028/29

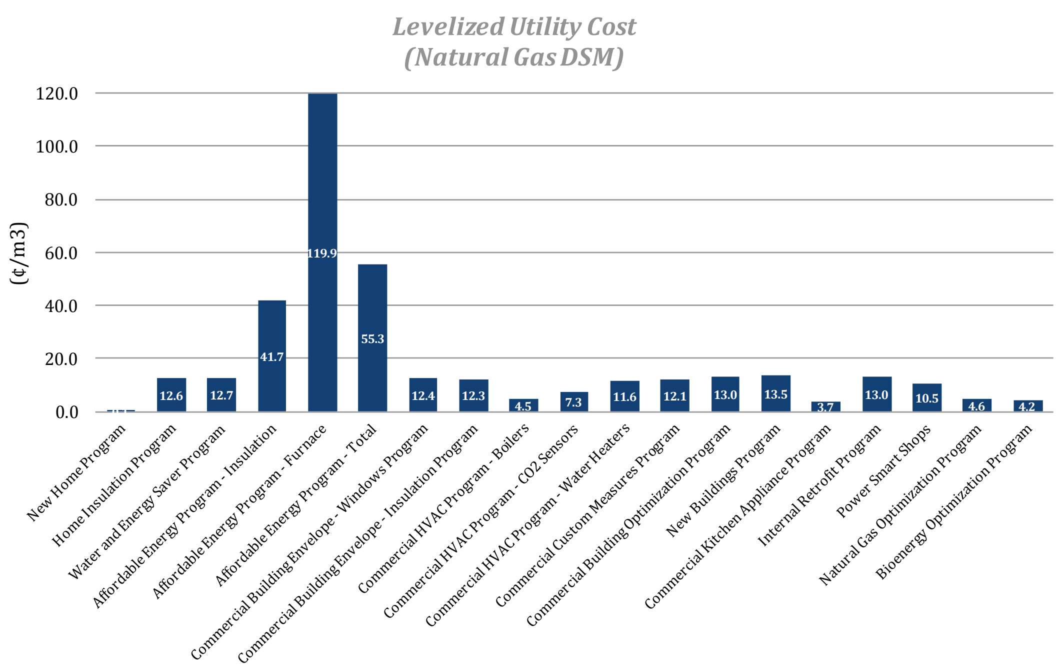
	Electric DSM				Natural Gas DSM				
	RIM	NUB	NPV	LUC (¢/kW.h)	RIM	NUB	NPV	LUC (¢/m³)	
Residential									
New Home Program	1.1	5.1	$7.3	0.3	0.8	(110.8)	($7.7)	0.1 *c*	
Home Insulation Program	1.2	1.6	$8.0	3.2	0.6	(0.6)	($18.4)	12.6	
Water and Energy Saver Program	0.7	0.0	($4.2)	3.0	0.5	(0.6)	($4.9)	12.7	
Affordable Energy Program									
Affordable Energy Program - Insulation	1.1	1.4	$4.9	3.4	0.3	(0.2)	($31.7)	41.7 **	
Affordable Energy Program - Furnace	n/a	n/a	n/a	n/a	0.2	(0.1)	($17.3)	119.9 **	
Affordable Energy Program - Total	1.1	1.4	$4.9	3.4	0.3	(0.1)	($48.9)	55.3 **	
Refrigerator Retirement Program	0.6	(0.7)	($10.8)	2.3	0.8	0.0	$1.4	- *i*	
Residential LED Lighting Program	0.8	0.3	($1.2)	2.4	0.8	0.0	$0.5	0.0 *i*	
Community Geothermal Program	0.9	0.5	($7.7)	2.5	0.0	0.0	$0.0	0.0	
Residential Programs Total	1.0	0.9	($3.8)	2.2	0.5	(0.4)	($78.1)	20.9	
Commercial									
Commercial Lighting Program	0.9	0.7	($22.3)	2.4	0.8	0.0	$1.2	0.0 *i*	
LED Roadway Lighting Conversion Program	0.8	0.8	($6.9)	3.3	n/a	n/a	n/a	n/a	
Commercial Building Envelope - Windows Program	1.2	1.7	$6.0	2.5	0.6	(0.3)	($6.5)	12.4	
Commercial Building Envelope - Insulation Program	1.2	1.6	$5.0	2.8	0.6	(0.3)	($19.5)	12.3	
Commercial Geothermal Program	1.0	0.9	($4.1)	3.2	n/a	n/a	n/a	n/a	
Commercial HVAC Program - Boilers	-	-	-	-	0.8	(0.8)	($4.2)	4.5 *c*	
Commercial HVAC Program - Chillers	0.7	(0.7)	($2.9)	1.4	n/a	n/a	n/a	n/a	
Commercial HVAC Program - CO2 Sensors	1.7	3.5	$0.9	2.6	0.7	(0.5)	($2.2)	7.3	
Commercial HVAC Program - Water Heaters	n/a	n/a	n/a	n/a	0.6	(0.4)	($0.9)	11.6	
Commercial Custom Measures Program	1.1	1.2	$1.4	3.2	0.6	(0.3)	($2.8)	12.1	
Commercial Building Optimization Program	0.9	0.6	($1.1)	2.8	0.6	(0.3)	($3.8)	13.0	
New Buildings Program	1.4	3.0	$28.6	1.7	0.6	(0.2)	($3.9)	13.5	
Commercial Refrigeration Program	0.9	0.6	($2.5)	1.1	0.8	0.0	($0.6)	- *i*	
Commercial Kitchen Appliance Program	1.7	13.1	$2.6	0.7	0.7	(1.5)	($1.1)	3.7	
Network Energy Management Program	1.1	2.3	$0.8	0.9	0.9	0.0	$0.0	- *i*	
Internal Retrofit Program	1.2	1.2	$0.4	5.4	1.9	1.9	($0.1)	13.0	
Power Smart Shops	0.9	0.6	($0.5)	2.7	0.6	(0.7)	($0.1)	10.5	
Commercial Programs Total	1.0	1.0	$5.3	2.4	0.6	(0.4)	($44.6)	10.8	
Industrial									
Performance Optimization Program	0.9	0.8	($19.3)	2.6	n/a	n/a	n/a	n/a	
Natural Gas Optimization Program	n/a	n/a	n/a	n/a	0.8	(0.5)	($3.2)	4.6	
Industrial Programs Total	0.9	0.8	($19.3)	2.6	0.8	(0.5)	($3.2)	4.6	
Energy Efficiency Subtotal	1.0	0.9	($17.8)	2.4	0.6	(0.4)	($125.8)	14.8	
Load Management									
Curtailable Rate Program	1.4	1.4	$32.2	n/a	n/a	n/a	n/a	n/a	
Load Management Programs Total	1.4	1.4	$32.2	n/a	n/a	n/a	n/a	n/a	
Load Displacement & Alternative Energy									
Bioenergy Optimization Program	1.0	1.1	$1.2	1.4	0.8	(0.4)	($1.1)	4.2	
Customer Sited Load Displacement	1.2	2.0	$74.3	1.0	n/a	n/a	n/a	n/a	
Load Displacement & Alt. Energy Programs Total	1.1	1.9	$75.4	1.0	0.8	(0.4)	($1.1)	4.2	
Conservation Rates									
Conservation Rates - Residential	0.8	(1.8)	($35.3)	0.8	n/a	n/a	n/a	n/a	
Conservation Rates - Commercial	1.1	2.3	$18.4	0.6	n/a	n/a	n/a	n/a	
Conservation Rates Total	0.9	0.4	($17.0)	0.7	n/a	n/a	n/a	n/a	
Fuel Choice									
Fuel Choice	1.0	1.0	$1.2	1.3	0.0	0.0	$0.0	0.0	
Fuel Choice Total	1.0	1.0	$1.2	1.3	0.0	0.0	$0.0	0.0	
Program Impacts Total	1.0	1.1	$74.1	1.6	0.6	(0.4)	($126.9)	14.5	
Program Support and Contingency Costs	-	-	($59.9)	-	-	-	($25.4)	-	
Program Impacts Total (Incl. Support and Contingency Costs)	1.0	1.0	$14.3	1.8	0.5	(0.3)	($152.3)	18.5	
Other Internal DSM Investments									
Afforedable Energy Fund	-	-	($0.9)	-	-	-	($0.7)	-	
Overall Portfolio Metric	1.0	1.0	$13.3	1.8	0.5	(0.3)	($153.0)	18.6	13.5 *(4)*

Notes:
*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*
AEP Electric - Total:
Excluding AEF costs, RIM is 1.4, NUB is 3.8, NPV is $12.8M, and LUC is 1.3 ¢/kW.h
AEP Natural Gas - Total:
Excluding AEF costs, without Furnance Replacement Program, RIM is 0.6, NUB is -1.1, NPV is -$9.3M, and LUC is 6.8 ¢/m3
c Program assumption includes savings from Codes & Standards
i Program reflects natural gas interactive effects
1) Overall RIM, NUB, and NPV portfolio metrics include Curtailable Rate Program and do not include Customer Service Initiatives / Financial Loan Programs
2) Overall LUC porfolio metric does not inlcude Curtailable Rate Program
3) Overall portfolio metrics include all support, contingency and Affordable Energy Fund Expenditures and Furance Replacement Program
4) Excluding the Affordable Energy Program, overall natural gas LUC is 13.5 ¢/m3

The following chart provides the Levelized Utility Cost of the electric program offerings in the 2014-2017 Power Smart Plan - 15 year supplemental report.



The following chart provides the Levelized Utility Cost of the natural gas program offerings in the 2014-2017 Power Smart Plan - 15 year supplemental report.



2.3.3 Customer Perspective

Metrics

The following table outlines the cost effectiveness, from a participating customer perspective, of the program offerings provided in the 2014-2017 Power Smart Plan - 15 year supplemental report.

Customer DSM Metrics
2014/15 - 2028/29

	Electric DSM			Natural Gas DSM			
	Payback	PC	PC NPV	Payback	PC	PC NPV	
Residential							
New Home Program	8.7	3.1	$43.9	21.6	1.1	$4.4	w
Home Insulation Program	0.6	5.5	$32.7	4.4	2.4	$22.8	
Water and Energy Saver Program	0.0	8.4	$17.7	-	29.5	$20.7	^ w
Affordable Energy Program							
Affordable Energy Program - Insulation	0.5	4.7	$31.5	1.7	2.1	$23.0	** w
Affordable Energy Program - Furance	n/a	n/a	n/a	-	6.8	$13.8	** ^
Affordable Energy Program - Total	0.5	4.7	$31.5	1.7	2.6	$36.8	** ^ w
Refrigerator Retirement Program	1.9	3.9	$16.6	0.0	-	($5.8)	
Residential LED Lighting Program	0.5	5.7	$5.1	0.0	0.0	($2.1)	
Community Geothermal Program	10.9	1.3	$17.0	0.0	0.0	$0.0	
Commercial							
Commercial Lighting Program	2.3	3.1	$178.6	-	-	($6.3)	
LED Roadway Lighting Conversion Program	0.0	1.4	$13.0	n/a	n/a	n/a	
Commercial Building Envelope - Windows Program	1.5	4.3	$21.2	2.2	2.3	$9.0	
Commercial Building Envelope - Insulation Program	0.7	5.4	$21.7	2.6	2.6	$30.6	
Commercial Geothermal Program	3.7	2.2	$48.8	n/a	n/a	n/a	
Commercial HVAC Program - Boilers	-	-	-	2.4	3.9	$12.3	
Commercial HVAC Program - Chillers	1.3	3.2	$5.6	n/a	n/a	n/a	
Commercial HVAC Program - CO2 Sensors	0.7	8.8	$1.0	1.4	5.4	$5.3	
Commercial HVAC Program - Water Heaters	n/a	n/a	n/a	6.0	1.8	$0.9	
Commercial Custom Measures Program	8.5	1.7	$6.3	6.9	2.2	$3.1	
Commercial Building Optimization Program	1.3	4.4	$6.1	3.0	2.3	$4.7	
New Buildings Program	9.3	1.9	$32.2	25.3	0.8	($2.4)	
Commercial Refrigeration Program	0.2	5.4	$33.4	-	-	$3.9	
Commercial Kitchen Appliance Program	0.1	23.7	$6.6	0.1	18.7	$10.0	w
Network Energy Management Program	1.7	2.0	$3.2	-	-	($0.3)	
Internal Retrofit Program	0.0	1.0	$0.0	0.0	n/a	n/a	
Power Smart Shops	2.1	3.8	$3.0	0.4	12.9	$0.0	
Industrial							
Performance Optimization Program	0.9	2.7	$176.0	n/a	n/a	n/a	
Natural Gas Optimization Program	n/a	n/a	n/a	7.9	1.5	$4.3	
Load Management							
Curtailable Rate Program	0.0	0.0	$0.0	n/a	n/a	n/a	
Load Displacement & Alternative Energy							
Bioenergy Optimization Program	3.9	1.7	$16.4	4.8	2.1	$2.8	
Customer Sited Load Displacement	1.5	1.2	$82.5	n/a	n/a	n/a	
Conservation Rates							
Conservation Rates - Residential	0.0	0.0	$139.7	n/a	n/a	n/a	
Conservation Rates - Commercial	0.0	0.0	$144.7	n/a	n/a	n/a	
Fuel Choice							
Fuel Choice	2.0	4.4	$217.9	0.0	0.0	$0.0	
Overall Portfolio Metric	n/a	2.5	$1,322.4	n/a	2.3	$154.7	

Notes:

*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*

^ Program with nil or negative customer costs

AEP Electric - Total:
Excluding AEF costs, Payback is 2.7, PC is 4.3, and PC NPV is $27.3M

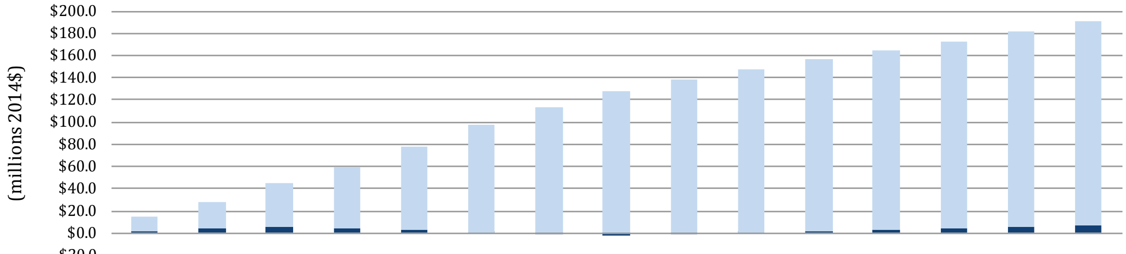
AEP Natural Gas - Total:
Excluding AEF costs, without Furnace Replacement Program, Payback is 10.7, PC is 1.4, and PC NPV is $7.7M

w Payback, PC and PC NPV include Water Savings Benefits

Combined Customer Bill Reductions

The following graph depicts customer bill reductions resulting from electric and natural gas programs outlined in the 2014-2017 Power Smart Plan - 15 year supplemental report. Power Smart programs are expected to save participating customers an additional $15.1 million in 2014/15 alone, $191 million in 2028/29 and $1.7 billion cumulatively by 2028/29.

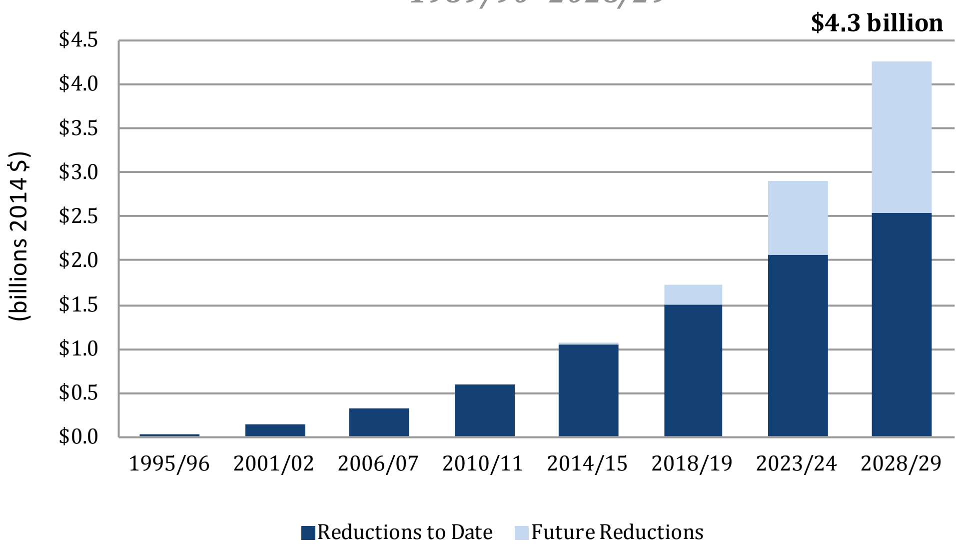
Customer Bill Reductions by fuel type
2014/15 - 2028/29



	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Electric	$13.3	$24.6	$39.3	$55.2	$75.7	$96.7	$113.8	$128.4	$137.9	$147.5	$154.7	$161.7	$168.4	$176.1	$184.2
Natural Gas	$1.8	$3.8	$5.7	$4.4	$2.7	$.9	-$.7	-$2.3	-$1.0	$.3	$1.7	$3.1	$4.5	$5.4	$6.4
Annual	$15.1	$28.4	$45.0	$59.7	$78.4	$97.7	$113.1	$126.1	$136.9	$147.9	$156.5	$164.8	$172.9	$181.6	$190.6
Cumulative	$15	$43	$88	$148	$227	$324	$437	$563	$700	$848	$1,005	$1,169	$1,342	$1,524	$1,715

When combined with bill reductions to date, Power Smart programs are expected to save participating customers $277 million in 2027/28 and over $4.3 billion dollars cumulatively by 2028/29.

Cumulative Customer Bill Reduction
1989/90 - 2028/29



2014 - 2017 Power Smart Plan
Annual Capacity Savings (MW)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	MW at Generation 2028/29	
RESIDENTIAL																	
Incentive Based																	
New Home Program	0.0	0.0	0.0	0.3	1.0	2.2	4.3	5.4	6.4	7.3	8.3	9.2	10.2	11.1	12.0	13.7	
Home Insulation Program	2.6	4.8	6.9	8.7	10.3	11.7	12.9	13.9	14.8	15.5	16.0	16.5	16.8	16.8	16.8	19.1	
Water and Energy Saver Program	0.6	1.2	1.7	1.9	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.8	
Affordable Energy Program	1.8	3.6	5.3	7.0	8.6	10.2	11.8	13.1	14.3	15.4	16.3	16.5	16.6	16.1	15.6	17.8	
Refrigerator Retirement Program	1.2	2.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	2.5	1.5	0.7	0.4	0.2	0.2	
Residential LED Lighting Program	0.5	0.6	0.9	1.2	1.6	1.7	1.7	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.6	
Community Geothermal Program	1.1	2.6	4.4	7.0	9.1	10.9	12.1	13.3	14.5	15.7	15.7	15.7	15.7	15.7	15.7	17.9	
Subtotal	7.8	15.3	22.7	29.6	36.2	42.6	48.7	53.0	57.3	61.3	62.7	63.3	63.8	64.0	64.1	73.1	10%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.3	0.5	0.8	1.0	1.3	1.6	1.8	2.1	2.3	2.6	2.9	3.1	3.4	3.7	3.9	4.5	
Power Smart PAYS Financing	0.1	0.2	0.3	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.6	
Residential Earth Power Loan	0.3	0.6	0.9	1.2	1.6	1.9	2.4	2.8	3.3	3.8	4.3	4.3	4.3	4.3	4.3	4.9	
Subtotal	0.6	1.3	2.0	2.7	3.4	4.2	4.9	5.7	6.5	7.4	8.3	8.6	9.0	9.3	9.7	11.0	1%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	9.1	18.7	27.7	36.0	44.6	49.4	54.0	58.3	62.3	66.1	67.7	68.9	69.0	69.9	70.7	80.6	
LED Roadway Lighting Conversion Program	0.7	1.5	2.1	2.9	3.8	4.6	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.9	
Commercial Building Envelope - Windows Program	1.0	1.9	2.7	3.5	4.3	5.1	5.9	6.7	7.6	8.4	9.2	10.1	10.9	11.7	12.6	14.3	
Commercial Building Envelope - Insulation Program	1.0	1.9	2.7	3.4	4.2	4.9	5.7	6.4	7.2	8.0	8.7	9.5	10.2	11.0	11.8	13.4	
Commercial Geothermal Program	0.4	1.3	2.3	3.5	4.9	6.3	7.8	9.6	11.4	13.3	15.3	17.4	19.6	21.9	24.3	27.7	
Commercial HVAC Program - Chillers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Commercial HVAC Program - CO2 Sensors	0.1	0.1	0.2	0.3	0.5	0.6	0.8	0.9	1.1	1.3	1.3	1.3	1.3	1.3	1.3	1.4	
Commercial Custom Measures Program	0.2	0.5	0.8	1.1	1.4	1.8	2.1	2.5	2.9	3.3	3.7	4.1	4.6	5.1	5.7	6.5	
Commercial Building Optimization Program	0.1	0.2	0.4	0.5	0.7	0.9	1.2	1.4	1.7	2.0	2.2	2.4	2.5	2.7	2.9	3.3	
New Buildings Program	4.1	9.5	16.3	16.3	16.6	17.4	18.5	19.9	21.7	21.7	21.7	21.7	21.7	21.7	21.7	24.8	
Commercial Refrigeration Program	1.2	1.8	2.1	2.5	2.8	3.2	3.6	4.0	4.4	4.9	5.4	5.8	6.2	6.6	7.0	8.0	
Commercial Kitchen Appliance Program	0.6	1.5	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.7	3.1	
Network Energy Management Program	0.2	0.5	0.8	1.3	2.0	2.0	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.0	
Internal Retrofit Program	0.2	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Power Smart Shops	0.0	0.0	0.2	0.4	0.6	0.9	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.3	
Subtotal	18.8	39.7	61.4	75.0	89.6	100.3	110.8	121.1	131.6	140.2	146.6	152.6	157.5	163.4	169.3	193.0	26%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	
Subtotal	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0%
INDUSTRIAL																	
Performance Optimization Program	2.4	5.3	8.6	12.2	16.3	20.4	24.4	28.5	32.6	36.7	40.7	44.8	48.9	53.0	57.0	62.7	
Subtotal	2.4	5.3	8.6	12.2	16.3	20.4	24.4	28.5	32.6	36.7	40.7	44.8	48.9	53.0	57.0	62.7	9%
ENERGY EFFICIENCY SUBTOTAL	29.7	61.6	94.8	119.8	145.7	167.7	189.1	208.7	228.4	246.0	258.7	269.8	279.7	290.1	300.6	340.4	46%
LOAD MANAGEMENT																	
Curtailable Rate Program	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	160.9	
LOAD MANAGEMENT SUBTOTAL	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	146.2	160.9	23%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	1.5	3.1	4.3	5.5	6.3	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.8	
Customer Sited Load Displacement	21.9	34.1	50.9	61.9	77.9	81.9	85.9	85.9	85.9	85.9	85.9	85.9	85.9	85.9	85.9	94.5	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	23.4	37.2	55.1	67.3	84.2	89.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	102.3	14%
CONSERVATION RATES																	
Conservation Rates - Residential	0.0	0.0	0.0	0.0	3.1	10.9	12.0	13.1	14.5	15.9	16.1	16.3	16.5	16.7	16.9	19.2	
Conservation Rates - Commercial	0.0	0.0	0.0	0.0	0.0	5.2	11.4	15.4	16.6	17.8	19.0	20.3	21.6	23.0	24.3	27.8	
CONSERVATION RATES SUBTOTAL	0.0	0.0	0.0	0.0	3.1	16.1	23.3	28.5	31.0	33.7	35.1	36.6	38.1	39.7	41.2	47.0	6%
FUEL CHOICE																	
Fuel Choice	0.0	0.0	0.0	13.3	26.7	40.0	53.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	76.1	
FUEL CHOICE SUBTOTAL	0.0	0.0	0.0	13.3	26.7	40.0	53.4	66.7	66.7	66.7	66.7	66.7	66.7	66.7	66.7	76.1	10%
Impacts (at meter)	199	245	296	347	406	459	505	543	565	586	600	612	624	636	648		100%
Impacts (at generation)	220	272	329	386	453	513	565	609	634	657	673	687	700	713	727		
Codes, Standards & Regulations (at meter)	19	42	71	101	129	154	179	203	226	249	271	294	316	337	359		
Codes, Standards & Regulations (at generation)	22	48	81	115	147	176	204	231	258	284	309	335	360	385	409		
POWER SMART 2014 to 2028 Impacts (at meter)	219	287	367	448	535	613	684	746	791	834	871	906	939	973	1,007		
POWER SMART 2014 to 2028 Impacts (at generation)	243	319	411	502	600	689	769	840	891	940	982	1,022	1,059	1,098	1,136		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	240	240	240	240	240	240	240	240	239	239	239	238	238	237	237		
Incentive Based Program Impacts (at generation)	270	270	270	270	270	270	270	270	269	269	269	268	268	267	267		
Customer Service Initiatives Program Impacts (at meter)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
Customer Service Initiatives Program Impacts (at generation)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11		
Discontinued Programs (at meter)	46	46	42	38	50	50	50	50	50	50	50	50	50	50	50		
Discontinued Programs (at generation)	52	52	48	43	56	56	56	56	56	56	56	56	56	56	56		
Impacts of Codes & Standards (at meter)	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145		
Impacts of Codes & Standards (at generation)	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166		
TOTAL MW (at meter)	660	728	805	881	979	1,058	1,129	1,191	1,235	1,279	1,315	1,349	1,382	1,415	1,448		
TOTAL MW (at generation)	741	818	905	991	1,103	1,192	1,272	1,343	1,393	1,442	1,484	1,523	1,560	1,597	1,635		

Note: May not add up due to rounding

2014 - 2017 Power Smart Plan
Annual Energy Savings (GW.h)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	GW.h at Generation 2028/29	
RESIDENTIAL																	
Incentive Based																	
New Home Program	0.0	0.0	0.0	0.9	3.0	7.0	14.0	17.5	20.8	24.1	27.3	30.5	33.7	36.8	39.9	45.5	
Home Insulation Program	4.7	9.0	12.8	16.1	19.1	21.7	23.9	25.8	27.4	28.8	29.8	30.6	31.2	31.2	31.2	35.6	
Water and Energy Saver Program	2.9	5.8	8.7	9.8	10.9	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	14.0	
Affordable Energy Program	3.4	6.7	9.8	13.2	16.5	19.7	22.8	25.4	27.8	30.2	32.0	32.6	32.9	32.0	31.1	35.5	
Refrigerator Retirement Program	11.1	22.3	31.6	31.6	31.6	31.6	31.6	31.6	31.6	31.6	22.7	13.8	6.0	3.7	1.5	1.7	
Residential LED Lighting Program	2.2	2.5	3.9	5.2	6.6	7.1	7.1	6.2	6.2	6.2	6.2	6.2	6.2	6.2	5.9	6.8	
Community Geothermal Program	4.0	9.8	16.5	26.5	34.4	41.4	46.0	50.6	55.2	59.7	59.7	59.7	59.7	59.7	59.7	68.1	
Subtotal	28.5	56.1	83.3	103.3	122.2	140.8	157.7	169.3	181.2	192.8	190.1	185.8	182.0	182.0	181.7	207.1	7%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.5	
Power Smart PAYS Financing	0.4	0.8	1.2	1.6	2.0	2.4	2.7	3.0	3.4	3.7	4.0	4.3	4.6	4.9	5.2	6.0	
Residential Earth Power Loan	1.1	2.3	3.6	5.0	6.5	8.1	9.8	11.7	13.7	15.8	18.0	18.0	18.0	18.0	18.0	20.6	
Subtotal	2.0	4.1	6.3	8.6	11.0	13.5	16.0	18.7	21.5	24.5	27.5	28.3	29.1	29.9	30.7	35.0	1%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	32.8	67.2	99.4	129.5	160.3	177.7	194.1	209.7	224.1	237.8	243.6	247.7	248.3	251.3	254.3	289.9	
LED Roadway Lighting Conversion Program	5.1	10.0	14.4	19.7	25.9	31.6	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	35.3	40.3	
Commercial Building Envelope - Windows Program	2.5	4.8	6.8	8.8	10.9	12.9	15.0	17.0	19.1	21.2	23.3	25.5	27.6	29.7	31.8	36.3	
Commercial Building Envelope - Insulation Program	2.4	4.9	6.8	8.7	10.6	12.6	14.5	16.5	18.4	20.3	22.3	24.2	26.2	28.1	30.1	34.3	
Commercial Geothermal Program	1.6	5.3	9.8	14.8	20.4	26.4	32.8	40.0	47.6	55.6	64.0	72.8	82.0	91.6	101.6	115.8	
Commercial HVAC Program - Chillers	2.2	3.5	4.9	5.3	5.8	6.3	6.7	7.2	7.4	7.6	7.8	7.9	8.1	8.3	8.4	9.6	
Commercial HVAC Program - CO2 Sensors	0.1	0.2	0.3	0.5	0.6	0.8	1.0	1.3	1.5	1.8	1.8	1.8	1.8	1.7	1.7	2.0	
Commercial Custom Measures Program	0.9	1.9	2.9	4.1	5.3	6.6	7.9	9.3	10.8	12.3	13.9	15.6	17.3	19.4	21.6	24.6	
Commercial Building Optimization Program	0.5	1.0	1.8	2.6	3.5	4.6	5.8	7.1	8.4	9.8	10.7	11.8	12.6	13.5	14.4	16.4	
New Buildings Program	9.2	21.4	36.8	36.8	37.6	39.2	41.7	45.0	49.1	49.1	49.1	49.1	49.1	49.1	49.1	55.9	
Commercial Refrigeration Program	10.3	15.7	18.7	21.8	25.0	28.3	31.7	35.4	39.2	43.2	47.3	51.5	54.8	58.4	62.1	70.8	
Commercial Kitchen Appliance Program	0.6	1.3	2.3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.5	2.4	2.2	2.5	
Network Energy Management Program	0.4	1.2	2.2	3.6	5.2	5.2	5.1	5.0	4.9	4.7	4.7	4.7	4.7	4.7	4.7	5.4	
Internal Retrofit Program	1.1	2.1	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.7	2.7	2.7	2.7	2.7	3.1	
Power Smart Shops	0.0	0.2	0.7	1.4	2.2	3.1	3.3	3.5	3.6	3.8	3.9	3.9	3.9	3.9	3.9	4.5	
Subtotal	69.6	140.7	210.7	263.0	318.9	360.7	400.5	437.7	474.9	508.0	533.1	557.1	576.9	600.1	624.0	711.3	26%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.2	0.5	0.7	0.8	0.9	1.1	1.2	1.3	1.5	1.6	1.7	1.9	2.0	2.1	2.3	2.6	
Subtotal	0.2	0.5	0.7	0.8	0.9	1.1	1.2	1.3	1.5	1.6	1.7	1.9	2.0	2.1	2.3	2.6	0%
INDUSTRIAL																	
Performance Optimization Program	15.6	33.8	54.5	77.9	103.9	129.8	155.8	181.7	207.7	233.7	259.6	285.6	311.6	337.5	363.5	399.8	
Subtotal	15.6	33.8	54.5	77.9	103.9	129.8	155.8	181.7	207.7	233.7	259.6	285.6	311.6	337.5	363.5	399.8	15%
ENERGY EFFICIENCY SUBTOTAL	115.9	235.1	355.6	453.6	556.9	645.8	731.2	808.8	886.9	960.5	1,012.0	1,058.6	1,101.6	1,151.7	1,202.2	1,356.0	49%
LOAD MANAGEMENT																	
Curtailable Rate Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
LOAD MANAGEMENT SUBTOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	13.0	26.9	37.3	47.8	55.1	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	68.1	
Customer Sited Load Displacement	125.0	173.7	305.1	391.3	517.5	549.0	580.6	580.6	580.6	580.6	580.6	580.6	580.6	580.6	580.6	638.6	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	138.0	200.5	342.4	439.2	572.6	610.9	642.5	642.5	642.5	642.5	642.5	642.5	642.5	642.5	642.5	706.7	26%
CONSERVATION RATES																	
Conservation Rates - Residential	0.0	0.0	0.0	0.0	25.8	90.2	99.2	109.1	120.0	132.0	133.6	135.2	136.8	138.4	140.1	159.7	
Conservation Rates - Commercial	0.0	0.0	0.0	0.0	0.0	43.2	94.2	127.5	137.5	147.7	158.1	168.7	179.6	190.7	202.1	230.4	
CONSERVATION RATES SUBTOTAL	0.0	0.0	0.0	0.0	25.8	133.4	193.4	236.6	257.5	279.7	291.7	303.9	316.4	329.1	342.1	390.0	14%
FUEL CHOICE																	
Fuel Choice	0.0	0.0	0.0	50.1	100.3	150.4	200.6	250.7	250.7	250.7	250.7	250.7	250.7	250.7	250.7	285.8	
FUEL CHOICE SUBTOTAL	0.0	0.0	0.0	50.1	100.3	150.4	200.6	250.7	250.7	250.7	250.7	250.7	250.7	250.7	250.7	285.8	10%
Impacts (at meter)	254	436	698	943	1,256	1,541	1,768	1,939	2,038	2,133	2,197	2,256	2,311	2,374	2,438		100%
Impacts (at generation)	283	487	780	1,054	1,404	1,727	1,983	2,177	2,289	2,397	2,468	2,534	2,597	2,667	2,739		
Codes, Standards & Regulations (at meter)	70	152	249	343	426	504	577	646	713	778	842	906	967	1,027	1,087		
Codes, Standards & Regulations (at generation)	79	173	284	391	486	574	658	736	813	887	960	1,033	1,103	1,171	1,240		
POWER SMART 2014 to 2028 Impacts (at meter)	324	587	947	1,286	1,682	2,044	2,344	2,585	2,750	2,912	3,039	3,162	3,278	3,402	3,525		
POWER SMART 2014 to 2028 Impacts (at generation)	363	660	1,064	1,445	1,890	2,301	2,641	2,913	3,101	3,284	3,428	3,567	3,699	3,839	3,978		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	1,120	1,120	1,120	1,120	1,120	1,120	1,119	1,119	1,108	1,108	1,108	1,108	1,099	1,088	1,088		
Incentive Based Program Impacts (at generation)	1,258	1,258	1,258	1,258	1,258	1,258	1,257	1,257	1,245	1,245	1,245	1,245	1,234	1,221	1,221		
Customer Service Initiatives Program Impacts (at meter)	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25		
Customer Service Initiatives Program Impacts (at generation)	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29		
Discontinued Programs (at meter)	296	296	276	249	320	320	320	320	320	320	320	320	320	320	320		
Discontinued Programs (at generation)	336	335	313	282	362	362	362	362	362	363	363	363	363	363	363		
Impacts of Codes & Standards (at meter)	610	610	610	610	610	610	610	610	610	610	610	610	610	610	610		
Impacts of Codes & Standards (at generation)	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694		
TOTAL GW.h (at meter)	2,375	2,639	2,978	3,290	3,757	4,119	4,418	4,658	4,813	4,975	5,103	5,225	5,332	5,444	5,568		
TOTAL GW.h (at generation)	2,679	2,977	3,358	3,709	4,234	4,644	4,983	5,256	5,432	5,615	5,759	5,898	6,019	6,146	6,286		

Note: May not add up due to rounding

2014 - 2017 Power Smart Plan
Annual Utility Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$448	$496	$700	$626	$0	$0	$0	$0	$0	$0	$0	$0	$2,270	
Home Insulation Program	$2,148	$2,032	$1,900	$1,703	$1,536	$1,405	$1,167	$1,036	$953	$784	$643	$573	$511	$167	$0	$16,558	
Water and Energy Saver Program	$772	$772	$772	$780	$899	$1,020	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,015	
Affordable Energy Program	$347	$333	$1,008	$1,516	$1,476	$1,444	$1,411	$1,388	$1,367	$1,351	$1,338	$827	$711	$0	$0	$14,516	
Refrigerator Retirement Program	$2,329	$2,289	$1,951	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,570	
Residential LED Lighting Program	$1,025	$229	$219	$209	$209	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,893	
Community Geothermal Program	$1,567	$2,017	$2,354	$3,613	$2,703	$2,376	$1,612	$1,612	$1,612	$1,611	$0	$0	$0	$0	$0	$21,076	
Subtotal	$8,187	$7,672	$8,205	$8,269	$7,319	$6,945	$4,816	$4,036	$3,932	$3,746	$1,981	$1,399	$1,222	$167	$0	$67,898	9%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$8,614	$8,733	$8,356	$8,076	$8,213	$5,828	$5,670	$5,519	$5,331	$5,170	$4,979	$4,655	$4,385	$4,393	$4,404	$92,325	
LED Roadway Lighting Conversion Program	$6,199	$6,062	$5,162	$6,052	$6,788	$6,151	$4,006	$0	$0	$0	$0	$0	$0	$0	$0	$40,419	
Commercial Building Envelope - Windows Program	$950	$857	$752	$763	$763	$763	$763	$768	$768	$768	$777	$777	$777	$777	$777	$11,803	
Commercial Building Envelope - Insulation Program	$986	$987	$812	$812	$812	$812	$816	$816	$816	$816	$816	$816	$816	$816	$816	$12,564	
Commercial Geothermal Program	$970	$2,034	$2,351	$2,532	$2,748	$2,896	$3,037	$3,354	$3,508	$3,661	$3,799	$3,949	$4,103	$4,256	$4,410	$47,609	
Commercial HVAC Program - Chillers	$302	$308	$342	$191	$192	$195	$199	$204	$5	$5	$5	$5	$5	$5	$5	$1,969	
Commercial HVAC Program - CO2 Sensors	$35	$41	$43	$45	$47	$48	$50	$52	$53	$55	$2	$2	$2	$2	$2	$476	
Commercial Custom Measures Program	$427	$479	$489	$557	$594	$604	$640	$650	$687	$718	$755	$765	$802	$963	$1,010	$10,139	
Commercial Building Optimization Program	$252	$222	$241	$241	$258	$277	$277	$287	$287	$296	$296	$306	$306	$316	$332	$4,194	
New Buildings Program	$2,546	$3,091	$3,525	$459	$803	$1,090	$1,434	$1,721	$2,009	$515	$0	$0	$0	$0	$0	$17,194	
Commercial Refrigeration Program	$1,698	$1,531	$344	$362	$370	$381	$400	$419	$438	$457	$465	$478	$460	$479	$499	$8,781	
Commercial Kitchen Appliance Program	$50	$62	$75	$48	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$235	
Network Energy Management Program	$79	$111	$143	$175	$207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$715	
Internal Retrofit Program	$821	$886	$803	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,511	
Power Smart Shops	$0	$120	$191	$205	$218	$228	$122	$123	$117	$112	$108	$0	$0	$0	$0	$1,546	
Subtotal	$23,928	$25,523	$23,630	$20,518	$22,012	$19,273	$17,414	$13,912	$14,019	$12,575	$12,003	$11,753	$11,655	$12,008	$12,256	$252,479	35%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Performance Optimization Program	$5,902	$6,916	$7,930	$8,944	$9,958	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$143,443	
Subtotal	$5,902	$6,916	$7,930	$8,944	$9,958	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$10,379	$143,443	20%
ENERGY EFFICIENCY SUBTOTAL	$38,017	$40,112	$39,764	$37,731	$39,290	$36,597	$32,610	$28,328	$28,330	$26,701	$24,363	$23,531	$23,256	$22,554	$22,635	$463,820	63%
LOAD MANAGEMENT																	
Curtailable Rate Program	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$89,261	
LOAD MANAGEMENT SUBTOTAL	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$5,951	$89,261	12%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$2,045	$2,217	$1,767	$1,691	$1,260	$1,188	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,168	
Customer Sited Load Displacement	$1,560	$5,168	$21,400	$14,653	$20,572	$6,300	$6,300	$1,550	$1,530	$1,510	$775	$755	$755	$755	$755	$84,338	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$3,605	$7,385	$23,167	$16,344	$21,832	$7,489	$6,300	$1,550	$1,530	$1,510	$775	$755	$755	$755	$755	$94,506	13%
CONSERVATION RATES																	
Conservation Rates - Residential	$0	$0	$0	$2,199	$2,040	$2,805	$1,573	$1,000	$1,000	$1,000	$1,000	$750	$750	$750	$750	$15,618	
Conservation Rates - Commercial	$0	$0	$0	$1,466	$2,040	$2,805	$2,805	$1,101	$775	$805	$1,353	$2,370	$1,000	$952	$972	$18,444	
CONSERVATION RATES SUBTOTAL	$0	$0	$0	$3,664	$4,081	$5,611	$4,379	$2,101	$1,775	$1,805	$2,353	$3,120	$1,750	$1,702	$1,722	$34,062	5%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$9,902	$9,882	$9,882	$9,882	$9,882	$0	$0	$0	$0	$0	$0	$0	$49,428	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$9,902	$9,882	$9,882	$9,882	$9,882	$0	$0	$0	$0	$0	$0	$0	$49,428	7%
Subtotal of Programs	$47,572	$53,447	$68,882	$73,592	$81,034	$65,529	$59,121	$47,810	$37,587	$35,966	$33,442	$33,357	$31,712	$30,962	$31,063	$731,078	100%
Program Support	$4,282	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$64,120	
Contingency	$400	$800	$850	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$23,050	
Total Utility Costs (2014 to 2028)	$52,254	$58,522	$74,006	$79,367	$86,809	$71,303	$64,895	$53,585	$43,361	$42,240	$39,716	$39,631	$37,986	$37,236	$37,337	$818,248	
Total Committed to Date																$448,717	
TOTAL UTILITY COSTS (1989 to 2028)	$52,254	$58,522	$74,006	$79,367	$86,809	$71,303	$64,895	$53,585	$43,361	$42,240	$39,716	$39,631	$37,986	$37,236	$37,337	$1,266,965	

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Administration Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$448	$496	$700	$626	$0	$0	$0	$0	$0	$0	$0	$0	$2,270	
Home Insulation Program	$972	$979	$962	$871	$803	$766	$613	$563	$554	$456	$379	$369	$362	$167	$0	$8,817	
Water and Energy Saver Program	$632	$632	$632	$50	$50	$50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,047	
Affordable Energy Program	$112	$108	$791	$979	$959	$944	$927	$916	$904	$896	$891	$512	$428	$0	$0	$9,367	
Refrigerator Retirement Program	$1,779	$1,739	$1,501	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,020	
Residential LED Lighting Program	$390	$229	$219	$209	$209	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,258	
Community Geothermal Program	$275	$187	$202	$358	$94	$89	$79	$79	$79	$79	$0	$0	$0	$0	$0	$1,521	
Subtotal	$4,160	$3,875	$4,308	$2,915	$2,611	$2,549	$2,245	$1,559	$1,538	$1,431	$1,270	$881	$790	$167	$0	$30,300	14%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$2,225	$33,379	
LED Roadway Lighting Conversion Program	$420	$420	$420	$420	$420	$420	$420	$0	$0	$0	$0	$0	$0	$0	$0	$2,938	
Commercial Building Envelope - Windows Program	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$408	$6,119	
Commercial Building Envelope - Insulation Program	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$6,394	
Commercial Geothermal Program	$304	$576	$582	$585	$589	$596	$595	$601	$604	$606	$593	$592	$595	$598	$601	$8,616	
Commercial HVAC Program - Chillers	$79	$79	$79	$79	$79	$79	$79	$79	$5	$5	$5	$5	$5	$5	$5	$669	
Commercial HVAC Program - CO2 Sensors	$32	$32	$32	$32	$32	$32	$32	$32	$32	$32	$2	$2	$2	$2	$2	$326	
Commercial Custom Measures Program	$241	$283	$283	$327	$349	$349	$371	$371	$393	$415	$437	$437	$459	$547	$569	$5,827	
Commercial Building Optimization Program	$206	$176	$176	$176	$176	$176	$176	$176	$176	$176	$176	$176	$176	$176	$176	$2,669	
New Buildings Program	$821	$791	$650	$459	$515	$515	$571	$571	$571	$515	$0	$0	$0	$0	$0	$5,982	
Commercial Refrigeration Program	$1,270	$1,270	$170	$170	$170	$170	$170	$170	$170	$170	$170	$170	$170	$170	$170	$4,744	
Commercial Kitchen Appliance Program	$10	$10	$10	$8	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39	
Network Energy Management Program	$31	$31	$31	$31	$31	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$155	
Internal Retrofit Program	$821	$886	$803	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,511	
Power Smart Shops	$0	$83	$67	$67	$67	$67	$67	$67	$67	$67	$67	$0	$0	$0	$0	$683	
Subtotal	$7,293	$7,696	$6,361	$5,412	$5,487	$5,462	$5,539	$5,125	$5,076	$5,045	$4,508	$4,441	$4,466	$4,556	$4,581	$81,051	38%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Performance Optimization Program	$2,342	$2,763	$3,184	$3,605	$4,026	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$60,388	
Subtotal	$2,342	$2,763	$3,184	$3,605	$4,026	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$4,447	$60,388	29%
ENERGY EFFICIENCY SUBTOTAL	$13,796	$14,335	$13,854	$11,932	$12,124	$12,458	$12,231	$11,131	$11,061	$10,923	$10,225	$9,768	$9,703	$9,170	$9,028	$171,739	81%
LOAD MANAGEMENT																	
Curtailable Rate Program	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$60	
LOAD MANAGEMENT SUBTOTAL	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$4	$60	0%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$233	$268	$238	$250	$219	$206	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,414	
Customer Sited Load Displacement	$60	$120	$190	$210	$150	$70	$70	$50	$30	$10	$25	$5	$5	$5	$5	$1,005	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$293	$388	$428	$460	$369	$276	$70	$50	$30	$10	$25	$5	$5	$5	$5	$2,419	1%
CONSERVATION RATES																	
Conservation Rates - Residential	$0	$0	$0	$2,199	$2,040	$2,805	$1,573	$1,000	$1,000	$1,000	$1,000	$750	$750	$750	$750	$15,618	
Conservation Rates - Commercial	$0	$0	$0	$1,466	$2,040	$2,805	$2,805	$1,101	$775	$805	$1,353	$2,370	$1,000	$952	$972	$18,444	
CONSERVATION RATES SUBTOTAL	$0	$0	$0	$3,664	$4,081	$5,611	$4,379	$2,101	$1,775	$1,805	$2,353	$3,120	$1,750	$1,702	$1,722	$34,062	16%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$668	$647	$647	$647	$647	$0	$0	$0	$0	$0	$0	$0	$3,258	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$668	$647	$647	$647	$647	$0	$0	$0	$0	$0	$0	$0	$3,258	2%
Subtotal of Programs	$14,093	$14,727	$14,285	$16,729	$17,225	$18,996	$17,331	$13,933	$12,871	$12,741	$12,608	$12,897	$11,462	$10,881	$10,759	$211,538	100%
Program Support	$4,282	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$4,274	$64,120	
Contingency	$400	$800	$850	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$23,050	
Total Adminstration Costs (2014 to 2028)	$18,774	$19,801	$19,409	$22,503	$23,000	$24,771	$23,105	$19,707	$18,645	$19,016	$18,882	$19,171	$17,736	$17,155	$17,033	$298,708	
Total Committed to Date																$189,749	
TOTAL ADMINISTRATION COSTS (1989 to 2028)	$18,774	$19,801	$19,409	$22,503	$23,000	$24,771	$23,105	$19,707	$18,645	$19,016	$18,882	$19,171	$17,736	$17,155	$17,033	$488,457	

Note: May not add up due to rounding.

ELECTRIC DSM

APPENDIX A.5

2014 - 2017 Power Smart Plan
Annual Incentive Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Home Insulation Program	$1,175	$1,053	$938	$832	$733	$640	$554	$473	$399	$329	$264	$204	$149	$0	$0	$7,741	
Water and Energy Saver Program	$140	$140	$140	$730	$849	$970	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,968	
Affordable Energy Program	$235	$225	$217	$537	$517	$500	$485	$472	$462	$454	$447	$315	$283	$0	$0	$5,149	
Refrigerator Retirement Program	$550	$550	$450	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,550	
Residential LED Lighting Program	$635	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$635	
Community Geothermal Program	$1,292	$1,830	$2,153	$3,255	$2,609	$2,286	$1,533	$1,533	$1,533	$1,532	$0	$0	$0	$0	$0	$19,555	
Subtotal	$4,027	$3,797	$3,897	$5,354	$4,708	$4,396	$2,571	$2,478	$2,394	$2,315	$711	$519	$432	$0	$0	$37,598	7%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$6,389	$6,507	$6,131	$5,851	$5,988	$3,602	$3,444	$3,293	$3,105	$2,945	$2,754	$2,430	$2,160	$2,168	$2,179	$58,947	
LED Roadway Lighting Conversion Program	$5,779	$5,642	$4,742	$5,632	$6,368	$5,731	$3,587	$0	$0	$0	$0	$0	$0	$0	$0	$37,481	
Commercial Building Envelope - Windows Program	$542	$449	$344	$355	$355	$355	$355	$360	$360	$360	$369	$369	$369	$369	$370	$5,684	
Commercial Building Envelope - Insulation Program	$560	$561	$386	$385	$385	$385	$390	$390	$390	$390	$390	$390	$390	$390	$390	$6,170	
Commercial Geothermal Program	$666	$1,459	$1,770	$1,946	$2,159	$2,300	$2,442	$2,753	$2,904	$3,055	$3,206	$3,357	$3,508	$3,659	$3,810	$38,993	
Commercial HVAC Program - Chillers	$223	$229	$263	$112	$113	$116	$120	$125	$0	$0	$0	$0	$0	$0	$0	$1,300	
Commercial HVAC Program - CO2 Sensors	$3	$9	$11	$13	$15	$17	$18	$20	$22	$23	$0	$0	$0	$0	$0	$150	
Commercial Custom Measures Program	$186	$196	$206	$230	$245	$255	$269	$279	$294	$304	$318	$328	$343	$416	$441	$4,311	
Commercial Building Optimization Program	$46	$46	$65	$65	$82	$101	$101	$111	$111	$120	$120	$130	$130	$140	$157	$1,525	
New Buildings Program	$1,725	$2,300	$2,875	$0	$288	$575	$863	$1,150	$1,438	$0	$0	$0	$0	$0	$0	$11,213	
Commercial Refrigeration Program	$429	$261	$174	$193	$200	$212	$230	$249	$268	$287	$296	$308	$290	$310	$329	$4,037	
Commercial Kitchen Appliance Program	$40	$52	$64	$40	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$196	
Network Energy Management Program	$48	$80	$112	$144	$176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$560	
Internal Retrofit Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart Shops	$0	$37	$125	$138	$152	$161	$56	$57	$51	$46	$41	$0	$0	$0	$0	$863	
Subtotal	$16,635	$17,827	$17,268	$15,105	$16,525	$13,810	$11,875	$8,787	$8,942	$7,530	$7,495	$7,312	$7,189	$7,452	$7,675	$171,428	33%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Performance Optimization Program	$3,559	$4,153	$4,746	$5,339	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$83,055	
Subtotal	$3,559	$4,153	$4,746	$5,339	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$5,932	$83,055	16%
ENERGY EFFICIENCY SUBTOTAL	$24,221	$25,777	$25,911	$25,799	$27,166	$24,139	$20,379	$17,197	$17,269	$15,778	$14,138	$13,763	$13,553	$13,384	$13,607	$292,081	56%
LOAD MANAGEMENT																	
Curtailable Rate Program	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$89,201	
LOAD MANAGEMENT SUBTOTAL	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$5,947	$89,201	17%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$1,812	$1,949	$1,530	$1,441	$1,041	$982	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,754	
Customer Sited Load Displacement	$1,500	$5,048	$21,210	$14,443	$20,422	$6,230	$6,230	$1,500	$1,500	$1,500	$750	$750	$750	$750	$750	$83,333	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$3,312	$6,997	$22,740	$15,884	$21,462	$7,212	$6,230	$1,500	$1,500	$1,500	$750	$750	$750	$750	$750	$92,088	18%
CONSERVATION RATES																	
Conservation Rates - Residential	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Conservation Rates - Commercial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
CONSERVATION RATES SUBTOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$9,234	$9,234	$9,234	$9,234	$9,234	$0	$0	$0	$0	$0	$0	$0	$46,171	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$9,234	$9,234	$9,234	$9,234	$9,234	$0	$0	$0	$0	$0	$0	$0	$46,171	9%
Total Incentive Costs (2014 to 2028)	$33,480	$38,720	$54,597	$56,863	$63,809	$46,532	$41,790	$33,878	$24,716	$23,225	$20,835	$20,460	$20,250	$20,081	$20,304	$519,540	100%
Total Committed to Date																$262,568	
TOTAL INCENTIVE COSTS (1989 to 2028)	$33,480	$38,720	$54,597	$56,863	$63,809	$46,532	$41,790	$33,878	$24,716	$23,225	$20,835	$20,460	$20,250	$20,081	$20,304	$782,108	

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Capacity Savings (MW)
(Savings to Date)
(1989/90 - 2013/14)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Benchmark 2028/29	At Generation 2028/29
RESIDENTIAL																											
Incentive Based																											
Home Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	2.03	5.16	7.96	10.69	13.77	16.38	18.81	21.69	23.96	23.96	27.31
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.36	0.70	1.54	3.03	4.55	5.95	5.95	6.78
New Home Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.19	0.44	0.73	0.97	1.18	1.46	1.63	1.63	1.63	1.63	1.86
Refrigerator Retirement Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69	1.82	3.04	0.00	0.00
Community Geothermal Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.37	0.42
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.70	1.34	1.71	2.08	2.08	2.37
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.86	2.22	5.60	8.81	12.01	15.65	20.08	25.50	31.40	37.02	33.98	38.74
Customer Service Initiatives																											
Power Smart Residential Loan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.80	1.10	1.39	1.64	2.00	2.73	3.04	3.93	4.22	4.39	4.69	4.94	4.94	5.63
Residential Earth Power Loan	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.25	0.63	1.06	1.42	2.07	2.47	2.99	3.28	3.77	3.83	3.86	3.86	4.40
ecoEnergy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential PAYS Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08	0.10
Power Smart for Business PAYS Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.63	0.63	0.71
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.89	1.35	2.02	2.70	3.42	4.80	5.51	6.92	7.50	8.16	8.52	9.52	9.52	10.85
DISCONTINUED/COMPLETED																											
Appliances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.49	1.01	1.59	1.71	1.71	1.71	1.71	1.71	1.71	1.94
Seasonal LED Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.12	0.17	0.20	0.21	0.21	0.21	0.21	0.21	0.21	0.24
Outdoor Timer	0.29	0.52	0.90	1.23	1.51	1.86	1.99	2.28	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.72
Res Hot Water	0.00	0.00	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Water Heater Rental	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
Thermostat	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.04	0.04	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit/Demonstration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RBB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.43	0.43	0.43	0.43	0.43	0.49
Energy Efficient Light Fixtures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.21	0.33	0.43	0.59	0.74	0.74	0.74	0.74	0.85
Compact Fluorescent Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.64	3.11	4.15	5.69	10.18	17.72	21.33	21.33	21.33	21.33	20.96	23.90
PSEM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.10	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16
R2000 House	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06
Subtotal	0.29	0.52	0.96	1.30	1.57	1.92	2.06	2.36	2.51	2.55	2.56	2.56	2.64	2.70	2.67	4.35	5.87	7.52	9.79	15.00	23.21	26.98	27.13	27.13	27.13	26.76	30.51
RESIDENTIAL TOTAL	0.29	0.52	0.96	1.30	1.57	1.92	2.06	2.36	2.51	2.55	2.56	2.56	3.11	3.58	4.02	7.22	10.79	16.54	23.40	32.52	45.78	54.55	60.79	67.04	73.66	70.25	80.09
COMMERCIAL																											
Incentive Based																											
Commercial Lighting Program	0.00	0.00	0.00	0.50	2.59	5.72	9.17	10.78	11.57	15.14	16.37	17.35	18.54	19.65	21.68	24.22	27.65	31.14	34.05	38.51	42.30	45.75	48.78	55.96	62.46	62.46	71.20
Commercial Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.80	1.11	1.48	1.66	1.97	2.42	3.77	4.21	5.36	7.42	8.67	9.28	10.31	11.25	11.94	12.61	12.94	12.94	14.75
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.75	1.84	3.17	4.85	6.22	8.13	11.00	11.00	12.54
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.17	0.26	0.31	0.39	0.45	0.62	0.82	1.05	1.49	1.66	1.76	2.09	2.97	3.99	4.79	5.62	6.06	6.06	6.91
Internal Retrofit Program	0.00	0.00	0.00	0.04	0.33	0.56	0.65	0.74	0.87	1.03	1.10	1.22	1.26	1.36	1.69	2.16	2.41	2.83	3.00	3.24	3.54	4.04	6.76	8.10	9.21	9.21	10.50
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05	0.11	0.44	0.52	0.52	0.52	0.87	0.87	0.91	0.98	1.15	1.22	1.22	1.39	1.66	1.66	1.66	1.66	1.89
Commercial Refrigeration Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.84	1.34	1.63	1.92	2.13	3.50	4.22	4.22	4.81
Commercial HVAC Program - Chiller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
City of Winnipeg Power Smart Agreement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.27	1.61	2.00	2.14	2.20	2.38	2.48	2.58	2.62	2.62	2.62	2.98
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.24	0.28	0.36	0.47	0.47	0.47	0.54
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.05	0.11	0.14	0.16	0.17	0.18	0.18	0.20
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.14	0.14	0.14	0.14	0.14	0.16
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.04	0.04	0.01	0.01
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07	0.08
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	1.01	1.27	1.27	1.45
CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Smart Energy Manager Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.54	2.92	6.28	9.82	11.78	13.45	17.64	19.70	21.14	22.74	24.60	28.97	32.79	39.43	46.33	52.36	59.79	67.94	76.25	85.98	100.03	112.33	112.30	128.02
DISCONTINUED/COMPLETED																											
Commercial Showerhead	0.00	0.00	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.23
Infrared Heat Lamp	0.00	0.00	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.69
Livestock Waterer	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00	0.00
Roadway Lighting	0.00	0.00	0.91	3.13	5.37	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	7.94
Sentinel Lighting	0.00	0.00	0.51	1.11	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	2.03
Commercial Air Barrier	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.07	0.08	0.11	0.17	0.20	0.23	0.26	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.33
Agricultural Demand Controller	0.00	0.00	0.00	0.68	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.14
Commercial Air Conditioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aboriginal Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parking Lot Controllers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.27	0.27	0.00	0.00	0.00	0.00	0.00
Agricultural Heat Pads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66	1.00	1.19	1.59	1.99	2.20	2.61	2.71	2.77	3.24	3.49	3.59	3.87	4.05	4.05	4.05	4.05	4.62
Subtotal	0.00	0.00	2.23	5.74	9.00	10.64	10.68	10.75	10.76	11.43	11.80	12.05	12.49	12.91	13.16	13.58	13.69	13.75	14.23	14.66	14.81	15.09	15.01	15.01	15.01	14.91	16.99
COMMERCIAL TOTAL	0.00	0.00	2.23	6.28	11.92	16.92	20.49	22.54	24.21	29.08	31.50	33.18	35.23	37.51	42.12	46.37	53.12	60.08	66.59	74.45	82.75	91.34	100.99	115.03	127.34	127.21	145.02
INDUSTRIAL																											
Performance Optimization Program	0.00	0.00	0.00	0.00	0.00	0.29	1.08	4.60	5.78	37.36	39.13	39.45	48.40	52.93	54.07	57.64	61.68	63.18	66.25	68.71	72.03	75.49	78.95	87.50	90.81	90.81	99.89
Emergency Preparedness Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.29	1.08	4.60	5.78	37.36	39.13	39.45	48.40	52.93	54.07	57.64	61.68	63.18	66.25	68.71	72.03	75.49	78.95	87.50	90.81	90.81	99.89
DISCONTINUED/COMPLETED																											
Industrial (Basic)	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04
Retrofit/Demonstration GSL	0.00	0.00	0.00	0.31	0.38	1.59	4.30	4.30	4.30	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.77
High Efficiency Motors	0.00	0.00	0.07	0.73	1.33	1.81	2.30	3.03	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	4.17
Efficient Motors (QMR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.07	1.04	1.74	3.43	6.63	7.36	8.12	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.98
INDUSTRIAL TOTAL	0.00	0.00	0.07	1.04	1.74	3.72	7.71	11.96	13.90	45.52	47.29	47.61	56.56	61.09	62.23	65.80	69.84	71.34	74.41	76.87	80.19	83.65	87.11	95.66	98.97	98.97	108.86
EFFICIENCY PROGRAMS SUBTOTAL	0.29	0.52	3.27	8.62	15.24	22.56	30.26	36.85	40.63	77.14	81.35	83.36	94.90	102.19	108.38	119.39	133.75	147.96	164.39	183.85	208.72	229.55	248.89	277.74	299.97	296.43	333.97
CUSTOMER SELF-GENERATION PROGRAMS																											
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.30	14.30	14.30	14.30	14.30	14.30	14.35	25.28	27.78	0.05	0.05
RATE/LOAD MANAGEMENT PROGRAMS																											
Curtailable Rate Program	0.00	0.00	0.00	0.00	40.70	46.40	24.70	32.70	80.00	48.20	58.00	57.10	68.00	110.28	148.54	153.76	189.07	183.29	180.62	172.76	149.15	154.52	147.25	146.60	145.86	0.00	0.00
PROGRAM IMPACTS	0.29	0.52	3.27	8.62	55.94	68.96	54.96	69.55	120.63	125.34	139.35	140.46	162.90	212.47	256.91	273.15	337.12	345.55	359.31	370.90	372.17	398.36	410.48	449.61	473.61	296.48	334.03
CODES, STANDARDS & REGULATIONS	0.00	0.00	0.00	0.48	1.60	3.33	5.43	8.41	13.60	20.40	28.00	35.18	42.93	52.01	56.15	61.78	66.95	72.42	78.60	85.12	91.99	99.46	114.57	131.56	145.33	145.33	165.57
Total Impact @ Meter	0.29	0.52	3.27	9.10	57.54	72.29	60.38	77.97	134.22	145.74	167.35	175.64	205.83	264.48	313.06	334.93	404.07	417.97	437.91	456.03	464.15	497.83	525.06	581.17	618.94	441.81	
Total Impact @ Generation	0.33	0.59	3.72	10.33	63.90	80.40	67.54	87.09	149.25	162.37	186.53	195.99	229.61	294.58	348.38	372.95	449.61	465.62	488.33	509.21	519.28	557.31	588.51	651.72	694.58	499.60	499.60

Note: May not add up due to rounding.
** Includes savings for Downtown Office project based on planning assumptions*

2014 - 2017 Power Smart Plan
Annual Energy Savings (GW.h)
(Savings To Date)
(1989/90 - 2013/14)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Benchmark 2028/29	At Generation 2028/29
RESIDENTIAL																											
Incentive Based																											
Home Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.74	4.25	10.74	16.49	22.08	28.41	33.75	38.73	44.31	48.72	48.72	55.54
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55	1.10	1.96	4.23	6.43	9.29	11.99	11.99	13.67
New Home Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.63	1.86	2.87	3.68	4.27	5.04	5.52	5.52	5.52	5.52	6.29
Refrigerator Retirement Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.91	20.74	31.45	0.00	0.00
Community Geothermal Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.38	1.38	1.57
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.51	13.22	16.87	16.87	19.23
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.83	4.88	12.60	19.92	26.87	34.64	43.02	71.10	93.09	115.93	84.48	96.30
Customer Service Initiatives																											
Power Smart Residential Loan Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	1.56	2.16	2.73	3.21	3.86	4.60	5.22	6.87	7.42	7.75	8.34	8.82	8.82	10.06
Residential Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.99	2.83	4.78	6.14	8.79	10.17	11.22	11.82	12.80	12.93	13.00	13.00	14.82
ecoEnergy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.30	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.86
Solar H2O Heater	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05	0.05	0.05	0.06
Power Smart PAYS Financing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	0.31	0.31	0.36
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	2.02	3.44	6.31	8.75	10.76	14.15	16.15	18.85	20.00	21.37	22.07	22.94	22.94	26.16
DISCONTINUED/COMPLETED																											
Appliances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.55	7.60	12.07	12.75	12.75	12.75	12.75	12.75	12.75	14.53
Seasonal LED Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	1.34	2.30	3.07	3.23	3.23	3.23	3.23	3.23	3.23	3.68
Outdoor Timer	5.01	8.93	15.34	20.59	24.78	29.22	30.89	34.68	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	41.58
Res Hot Water	0.00	0.00	0.35	0.35	0.35	0.35	0.35	0.36	0.46	0.59	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.70
Water Heater Rental	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.25	0.42	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.55
Thermostat	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.41
Retrofit/Demonstration	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RBB	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.26	1.26	1.26	1.26	1.26	1.26	1.44
Energy Efficient Light Fixtures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	1.03	2.08	2.64	3.68	4.45	4.45	4.45	4.45	5.08
Compact Fluorescent Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.09	15.39	20.60	28.09	49.94	77.72	92.07	92.07	92.07	92.07	89.88	102.47
Power Smart Energy Manager	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.62	1.20	2.38	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	3.19
R2000 House	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.15	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.22
Subtotal	5.01	8.93	15.70	20.96	25.15	29.59	31.26	35.12	37.20	37.49	37.58	37.58	38.30	38.93	40.15	48.66	56.04	66.50	79.95	108.10	138.52	153.91	154.69	154.69	154.69	152.50	173.85
RESIDENTIAL TOTAL	5.01	8.93	15.70	20.96	25.15	29.59	31.26	35.12	37.20	37.49	37.58	37.58	39.21	40.96	43.59	56.80	69.67	89.87	114.02	151.11	192.02	216.93	247.15	269.84	293.56	259.92	296.31
COMMERCIAL																											
Incentive Based																											
Commercial Lighting Program	0.00	0.00	0.00	2.92	16.99	35.90	55.00	61.23	67.45	85.39	90.76	94.88	100.18	105.59	116.21	132.57	153.14	175.81	193.92	218.90	239.47	258.75	281.22	312.18	341.78	341.78	389.62
Commercial Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	1.12	1.79	2.86	3.23	4.02	5.05	7.76	8.75	11.12	15.30	18.63	20.21	23.61	25.99	27.77	29.86	31.05	31.05	35.40
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	1.87	4.07	6.55	9.73	12.50	16.27	21.92	21.92	24.99
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.35	0.56	0.67	0.89	1.02	1.37	1.79	2.29	3.19	3.95	4.46	5.23	7.29	9.67	11.75	13.83	14.99	14.99	17.09
Internal Retrofit Program	0.00	0.00	0.00	0.17	1.23	2.73	3.29	3.77	4.26	4.95	5.44	5.85	6.14	6.89	9.38	12.15	14.42	16.98	18.03	19.82	21.47	24.05	32.39	34.21	36.77	36.77	41.92
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	2.58	10.00	10.75	11.70	12.16	12.77	12.83	12.85	13.14	15.39	15.91	17.36	18.82	20.20	21.43	22.26	22.26	25.38
Commercial Refrigeration Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	3.05	4.26	5.53	6.97	8.69	21.25	28.57	28.57	32.58
Commercial HVAC Program - Chiller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.46	3.66	4.10	4.28	4.85	5.34	7.10	8.17	9.35	10.67	10.67	12.16
City of Winnipeg Power Smart Agreement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.63	1.17	7.61	9.60	10.12	10.34	10.83	11.15	11.47	11.61	11.61	11.61	13.23
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.32	0.38	0.47	0.61	0.61	0.61	0.70
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.47	0.60	0.71	0.74	0.76	0.76	0.87
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.69	0.69	0.69	0.69	0.69	0.78
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.62	0.88	0.88	2.34	4.60	3.72	4.25
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.18	0.18	0.18	0.69	0.69	0.79
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.30	5.63	6.78	6.78	7.73
CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.09	0.14	0.30	0.30	0.34
Power Smart Energy Manager Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	3.09	18.23	38.63	58.29	65.81	73.56	95.27	109.74	115.61	123.06	131.13	148.53	172.23	205.99	240.70	269.74	304.26	339.17	374.99	419.45	480.32	534.06	533.18	607.82
Customer Service Initiatives																											
Power Smart for Business PAYS Financing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.20	2.20	2.51
DISCONTINUED/COMPLETED																											
Commercial Showerhead	0.00	0.00	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.64
Infrared Heat Lamp	0.00	0.00	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	4.24
Livestock Waterer	0.00	0.00	0.00	0.00	0.00	0.17	0.31	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.00	0.00
Roadway Lighting	0.00	0.00	3.88	13.50	23.16	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	34.03
Sentinel Lighting	0.00	0.00	2.25	4.73	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	8.55
Commercial Air Barrier	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.18	0.20	0.28	0.45	0.55	0.63	0.72	0.75	0.78	0.78	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.95
Agricultural Demand Controller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Air Conditioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.04	0.20	0.20	0.29	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.36
Aboriginal Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parking Lot Controllers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	1.62	3.67	4.10	4.40	5.94	6.76	8.80	11.50	19.96	27.93	30.46	32.43	34.88	38.11	39.38	39.41	39.41	39.41	44.93
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.90	2.88	4.79	5.17	5.17	0.00	0.00	0.00	0.00	0.00
Agricultural Heat Pads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.51	5.51	6.68	9.23	11.59	12.90	15.39	16.39	17.03	21.75	24.30	25.41	28.37	30.24	30.24	30.24	30.24	34.48
Subtotal	0.00	0.00	11.30	23.39	35.82	42.68	42.83	43.81	44.70	50.27	52.79	54.41	58.64	62.06	65.51	70.82	80.32	90.84	99.12	105.55	109.49	115.68	113.65	113.69	113.69	113.31	129.18
COMMERCIAL TOTAL	0.00	0.00	11.30	26.48	54.04	81.31	101.11	109.62	118.26	145.55	162.53	170.02	181.70	193.19	214.04	243.05	286.31	331.54	368.87	409.81	448.66	490.67	533.10	594.01	649.94	648.69	739.50
INDUSTRIAL																											
Performance Optimization Program	0.00	0.00	0.00	0.00	0.00	2.42	7.21	35.10	43.52	85.88	107.70	110.85	142.93	170.52	181.46	207.61	238.59	249.35	276.39	294.86	319.61	347.88	373.07	441.26	470.18	470.18	517.19
Emergency Preparedness Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	2.42	7.21	35.10	43.52	85.88	107.70	110.85	142.93	170.52	181.46	207.61	238.59	249.35	276.39	294.86	319.61	347.88	373.07	441.26	470.18	470.18	517.19
DISCONTINUED/COMPLETED																											
Industrial (Basic)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Retrofit/Demonstration GSL	0.00	0.00	0.00	0.07	0.67	9.67	32.72	32.72	32.72	33.07	33.07	33.07	33.07	33.07	33.07	33.07	33.07	33.07	32.99	32.99	32.99	32.99	32.99	32.99	32.98	32.98	36.28
High Efficiency Motors	0.00	0.00	0.40	4.79	7.65	10.34	13.30	17.88	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	23.63
Efficient Motors (QMR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.40	4.87	8.33	20.02	46.02	50.61	54.21	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.48	54.48	54.48	54.48	54.48	54.48	54.47	54.47	59.92
INDUSTRIAL TOTAL	0.00	0.00	0.40	4.87	8.33	22.44	53.23	85.71	97.73	140.44	162.25	165.41	197.49	225.08	236.02	262.17	293.15	303.90	330.87	349.35	374.10	402.37	427.55	495.74	524.65	524.65	577.12
EFFICIENCY PROGRAMS SUBTOTAL	5.01	8.93	27.40	52.31	87.52	133.34	185.60	230.45	253.19	323.48	362.36	373.01	418.39	459.23	493.64	562.03	649.13	725.32	813.76	910.27	1,014.78	1,109.97	1,207.81	1,359.59	1,468.15	1,433.26	1,612.93
CUSTOMER SELF-GENERATION PROGRAMS																											
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.26	120.06	84.21	94.01	80.08	86.56	70.27	82.53	107.70	0.06	0.07
RATE/LOAD MANAGEMENT PROGRAMS																											
Curtailable Rate Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PROGRAM IMPACTS	5.01	8.93	27.40	52.31	87.52	133.34	185.60	230.45	253.19	323.48	362.36	373.01	418.39	459.23	493.64	562.03	659.39	845.38	897.97	1,004.28	1,094.86	1,196.53	1,278.08	1,442.12	1,575.85	1,433.33	1,613.01
CODES, STANDARDS & REGULATIONS	0.00	0.00	0.00	1.94	6.59	13.73	22.35	35.19	55.52	81.51	110.09	137.26	166.49	200.72	217.58	240.50	261.85	284.34	309.12	335.24	377.77	422.84	485.92	551.49	609.60	609.60	694.30
Total Impact @ Meter	5.01	8.93	27.40	54.25	94.11	147.07	207.95	265.64	308.71	404.98	472.45	510.27	584.89	659.94	711.22	802.53	921.24	1,129.72	1,207.10	1,339.52	1,472.63	1,619.37	1,764.00	1,993.61	2,185.45	2,042.93	
Total Impact @ Generation	5.71	10.18	31.22	61.64	106.95	166.77	234.93	299.40	347.96	455.93	531.90	574.83	658.55	742.94	800.89	903.87	1,037.49	1,270.22	1,358.84	1,508.67	1,659.98	1,825.87	1,990.39	2,248.94	2,465.47	2,307.30	2,307.30

Note: May not add up due to rounding.
** Includes savings for Downtown Office project based on planning assumptions*

2014 - 2017 Power Smart Plan
Annual Utility Costs
(1989/90 - 2013/14)
(000's in 2014 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative 2013/14
RESIDENTIAL																										
Incentive Based																										
Home Insulation Program	0	0	0	0	269	410	256	239	431	48	5	48	76	75	147	809	1,204	2,054	1,656	1,831	1,819	1,468	1,324	1,314	1,149	16,631
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	96	226	223	79	141	102	118	421	1,446
Lower Income First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	15	2	6	42	61	150	193	0	475
New Home Program	0	0	0	42	161	102	230	131	67	35	1	20	141	311	238	325	652	974	699	694	624	226	263	47	0	5,982
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	86	1,561	1,661	1,605	4,925
Communtity Geothermal Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	350	350
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	86	54	491	463	805	1,095	3,014
Subtotal	0	0	0	42	430	512	486	369	498	83	6	68	217	386	385	1,134	1,922	3,139	2,584	2,839	2,629	2,473	3,863	4,137	4,620	32,822
Customer Service Initiatives																										
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	48	83	21	10	0	1	10	-1	-6	-79	-40	-30	-74	51	-7
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	3	51	105	373	947	-100	77	225	174	110	90	129	81	2,264
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-11	-46	77	177	-21	154	108	119	-30	0	527
Residential PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	180	180
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	0	0	7
Subtotal	0	0	0	0	0	0	0	0	0	0	0	48	85	72	114	362	902	-13	252	198	256	179	178	25	312	2,971
Discontinued/Completed																										
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	22	15	11	103	1,663	2,115	1,880	431	13	1	1	0	6,253
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91	421	392	371	25	0	0	0	0	1,300
Outdoor Timer	210	306	262	204	100	58	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,178
Res Hot Water	0	0	186	0	0	0	2	65	27	16	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300
Water Heater Rental	0	0	0	0	0	0	20	423	418	80	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	946
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	76	37	11	0	0	0	0	0	146
Retrofit/Demonstration	0	69	29	129	0	0	5	0	0	0	0	0	0	0	0	15	50	0	0	0	0	0	0	0	0	295
RBB	0	0	56	13	0	0	0	0	0	0	0	0	0	18	30	5	71	26	0	0	0	0	0	0	0	220
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	3
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	168	537	416	201	261	327	0	0	1,909
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	0	0	0	0	0	0	0	21
Set Top Boxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	1	0	0	0	23
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	851	1,101	881	1,009	1,390	1,714	1,079	2	0	0	8,049
Subtotal	210	375	531	346	100	58	47	491	455	100	10	0	0	39	76	887	1,433	3,250	4,089	4,067	2,392	1,354	331	1	0	20,642
Residential Exploratory Programs																										
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	29	0	33
RESIDENTIAL TOTAL	210	375	531	387	530	570	533	861	953	183	16	116	302	498	576	2,382	4,257	6,375	6,925	7,104	5,277	4,007	4,374	4,191	4,932	56,468
COMMERCIAL																										
Incentive Based																										
Commercial Lighting Program	0	0	115	1,229	2,634	3,108	3,050	1,267	1,078	2,133	952	697	1,081	1,281	2,891	5,696	6,870	7,877	8,140	8,444	7,875	7,148	6,684	8,054	7,057	95,362
Commercial Earth Power Program	0	0	0	0	15	52	83	70	237	124	142	117	179	304	684	294	550	681	384	242	416	320	306	275	224	5,698
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	232	279	260	248	286	245	468	523	2,541
Commercial Windows Program	0	0	0	0	8	28	45	136	180	66	46	80	72	165	128	258	343	426	415	482	1,095	1,309	1,039	961	633	7,914
Internal Retrofit Program	0	0	124	295	493	594	172	223	184	243	120	309	146	301	661	754	642	850	653	778	1,158	1,987	785	842	645	12,959
Commercial Custom Measures Program	0	0	0	0	21	70	113	84	0	231	561	140	157	87	168	12	9	129	204	260	228	248	250	58	33	3,061
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	253	335	321	190	199	183	353	636	510	2,980
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	190	220	78	231	174	336	221	152	261	1,864
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	5	3,053	2,093	5,005	1,980	218	69	49	85	-47	-125	0	12,385
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60	47	148	69	66	61	0	451
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99	89	38	33	12	5	277
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	66	262	153	48	0	0	531
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	196	63	43	30	28	39	42	95	127	664
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	22	74	89	24	6	56	274
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	152	104	176	311	314	120	87	1,266
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	2	4
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	87	126	94	117	23	0	0	448
Subtotal	0	0	240	1,524	3,171	3,851	3,463	1,779	1,679	2,797	1,821	1,344	1,634	2,141	7,584	9,107	14,057	12,796	11,038	11,450	12,311	12,719	10,387	11,619	10,163	148,678
Customer Service Initiatives																										
Power Smart for Business PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91	91
Discontinued/Completed																										
Commercial Showerhead	0	69	127	37	4	128	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	365
Infrared Heat Lamp	0	19	304	35	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	363
Livestock Waterer	0	0	0	0	0	163	141	98	25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	431
Roadway Lighting	0	119	1,582	2,231	2,038	1,548	19	0	49	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,587
Sentinel Lighting	0	34	1,395	1,168	1,199	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,796
Commercial Air Barrier	0	0	0	0	9	30	48	104	82	3	11	35	23	19	20	7	4	0	6	0	0	0	0	0	0	401
Agricultural Demand Controller	0	0	34	666	227	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	927
Commercial Air Conditioning	0	0	0	0	1	2	3	85	80	0	0	0	8	57	0	146	11	0	0	0	0	0	0	1	0	394
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Parking Lot Controllers	0	0	0	0	41	140	226	120	108	202	22	55	217	118	307	388	1,150	993	638	413	552	569	296	10	0	6,566
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	30	24	10	5	0	0	0	111
Agricultural Heat Pads	0	0	0	0	0	0	3	72	37	96	96	51	64	73	65	138	79	71	66	46	125	106	8	1	0	1,196
Subtotal	0	241	3,442	4,138	3,523	2,011	439	479	382	306	129	141	311	266	391	680	1,245	1,106	740	483	686	681	305	11	0	22,137
Commercial Exploratory Programs																										
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
Subtotal	0	241	3,682	5,661	6,694	5,862	3,902	2,259	2,062	3,103	1,950	1,485	1,946	2,408	7,976	9,787	15,302	13,902	11,777	11,933	12,998	13,400	10,693	11,631	10,255	170,907
INDUSTRIAL																										
Performance Optimization Program	0	0	93	198	254	523	530	477	695	421	280	432	1,093	3,450	1,297	1,758	1,833	1,175	3,515	2,738	3,160	2,976	3,093	2,846	2,618	35,454
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88	76	7	1	1	0	173
Subtotal	0	0	93	198	254	523	530	477	695	421	280	432	1,093	3,450	1,297	1,758	1,833	1,175	3,515	2,826	3,235	2,983	3,094	2,846	2,618	30,163
Discontinued/Completed																										
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	67	338	362	651	1,118	379	348	89	12	5	0	0	0	0	0	41	0	0	0	0	0	0	0	3,409
High Efficiency Motors	0	24	329	799	640	508	466	505	680	49	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,004
Efficient Motors (QMR)	0	0	0	24	55	21	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	104
Subtotal	0	24	396	1,161	1,057	1,180	1,588	884	1,028	139	15	5	0	0	0	0	0	41	0	0	0	0	0	0	0	7,518
	0	24	489	1,360	1,311	1,703	2,118	1,361	1,723	560	295	437	1,093	3,450	1,297	1,758	1,833	1,216	3,515	2,827	3,235	2,983	3,094	2,846	2,618	43,144
EFFICIENCY PROGRAMS SUBTOTAL	210	640	4,701	7,408	8,535	8,136	6,553	4,480	4,738	3,846	2,261	2,038	3,341	6,355	9,849	13,927	21,392	21,494	22,217	21,864	21,510	20,391	18,161	18,668	17,805	270,519
CUSTOMER SELF-GENERATION PROGRAMS																										
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160	1,852	1,789	1,879	1,615	1,725	1,816	361	0	11,197
RATE/LOAD MANAGEMENT PROGRAMS																										
Curtailable Rate Program	0	0	0	91	673	1,654	1,488	1,458	1,262	1,612	1,993	2,556	3,369	5,080	6,652	6,669	7,435	7,274	7,211	6,978	6,262	6,172	6,106	5,972	6,070	94,036
Support Costs	0	380	3,655	4,393	3,121	1,736	2,063	1,657	1,319	1,711	2,435	3,338	3,002	3,798	3,880	4,330	4,602	2,835	3,141	4,133	4,125	3,510	3,874	3,439	2,489	72,965
GRAND TOTAL	210	1,020	8,357	11,893	12,330	11,526	10,103	7,595	7,318	7,169	6,690	7,932	9,711	15,233	20,381	24,926	33,589	33,454	34,358	34,853	33,512	31,798	29,957	28,440	26,364	448,717

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Program Administration Costs
(1989/90 - 2013/14)
(000's in 2014 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative 2013/14
RESIDENTIAL																										
Incentive Based																										
Home Insulation Program	0	0	0	0	269	410	256	239	431	48	5	48	76	75	147	293	461	310	231	230	204	230	254	457	441	5,115
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	47	0	185	918	1,262	86	35	26	105	2,663
Lower Income First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	15	2	6	42	61	150	0	0	282
New Home Program	0	0	0	42	161	102	230	131	67	35	1	20	141	311	238	314	580	837	578	584	502	96	215	35	0	5,217
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	86	1,224	1,287	1,232	3,842
Communtity Geothermal Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	153	153
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	86	54	90	269	564	900	1,983
Subtotal	0	0	0	42	430	512	486	369	498	83	6	68	217	386	385	606	1,113	1,161	995	1,824	2,074	649	2,148	2,369	2,832	19,255
Customer Service Initiatives																										
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	48	83	21	10	0	1	10	-1	-6	-79	-40	-30	-74	51	-7
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	3	51	105	373	947	-100	77	225	174	110	90	129	81	2,263
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-11	-46	77	177	-21	154	108	119	-30	0	527
Residential PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	180	180
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	0	0	7
Subtotal	0	0	0	0	0	0	0	0	0	0	0	48	85	72	114	362	902	-13	252	198	256	179	178	24	312	2,970
Discontinued/Completed																										
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	22	15	11	103	607	659	442	116	12	1	1	0	1,990
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58	250	270	298	2	0	0	0	0	878
Outdoor Timer	158	234	199	167	69	58	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	923
Res Hot Water	0	0	176	0	0	0	2	65	27	16	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	290
Water Heater Rental	0	0	0	0	0	0	20	423	418	80	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	946
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	52	26	5	0	0	0	0	0	105
Retrofit/Demonstration	0	69	29	129	0	0	0	0	0	0	0	0	0	0	0	15	50	0	0	0	0	0	0	0	0	290
RBB	0	0	29	13	0	0	0	0	0	0	0	0	0	18	30	5	71	0	0	0	0	0	0	0	0	166
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	3
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	66	425	340	133	102	192	0	0	1,258
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Set Top Boxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	682	818	631	736	682	554	437	2	0	0	4,564
Subtotal	158	303	432	309	69	58	42	491	455	100	10	0	0	39	76	717	1,111	1,607	2,115	1,767	806	551	196	1	0	11,413
Residential Exploratory Programs																										
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	0	0	29	0	50
RESIDENTIAL TOTAL	158	303	432	350	499	570	528	861	953	183	16	116	302	498	576	1,685	3,126	2,755	3,363	3,789	3,157	1,378	2,521	2,423	3,145	33,688
COMMERCIAL																										
Incentive Based																										
Commercial Lighting Program	0	0	115	906	1,009	836	675	462	600	448	330	353	432	875	1,194	2,023	1,970	2,331	2,220	1,999	2,054	2,002	1,943	1,831	1,829	28,437
Commercial Earth Power Program	0	0	0	0	15	52	83	38	80	29	14	42	85	153	306	157	217	217	231	142	131	105	128	85	82	2,389
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	153	154	47	48	34	32	153	136	757
Commercial Windows Program	0	0	0	0	8	28	45	84	80	9	1	26	14	45	34	65	57	167	174	109	125	127	122	178	132	1,628
Internal Retrofit Program	0	0	124	240	216	192	66	71	74	66	47	96	53	110	130	190	204	246	289	569	252	182	158	320	161	4,057
Commercial Custom Measures Program	0	0	0	0	21	70	113	52	0	96	94	85	102	64	68	9	1	84	37	224	93	96	145	11	12	1,477
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	253	235	210	102	104	90	141	124	118	1,378
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	76	23	15	14	18	18	18	9	16	207
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	5	2,214	1,090	1,046	468	59	69	49	-84	-122	-144	0	4,647
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37	41	44	37	30	0	190
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	38	14	19	9	3	132
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	66	260	149	48	0	0	525
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	196	63	43	22	19	29	28	71	78	549
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	69	76	24	6	5	203
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	104	176	193	197	39	36	745
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	3
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	123	94	117	23	0	0	359
Subtotal	0	0	240	1,146	1,269	1,177	983	707	834	647	486	601	686	1,251	3,945	3,534	4,020	3,989	3,433	3,699	3,570	3,192	2,943	2,723	2,609	47,682
Customer Service Initiatives																										
Power Smart for Business PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91	91
Discontinued/Completed																										
Commercial Showerhead	0	69	96	37	4	128	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	333
Infrared Heat Lamp	0	19	164	35	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	223
Livestock Waterer	0	0	0	0	0	141	122	87	25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	380
Roadway Lighting	0	119	1,582	2,231	2,038	1,548	19	0	49	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,587
Sentinel Lighting	0	34	1,395	1,168	1,199	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,796
Commercial Air Barrier	0	0	0	0	9	30	48	84	80	1	1	18	11	10	10	5	1	0	1	0	0	0	0	0	0	308
Agricultural Demand Controller	0	0	34	480	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	677
Commercial Air Conditioning	0	0	0	0	1	2	3	84	80	0	0	0	3	21	0	12	2	0	0	0	0	0	0	1	0	209
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parking Lot Controllers	0	0	0	0	41	140	226	84	80	72	5	34	165	94	231	304	531	193	126	155	157	85	33	1	0	2,759
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	16	5	7	1	0	0	0	43
Agricultural Heat Pads	0	0	0	0	0	0	3	72	37	43	31	22	25	34	29	86	47	46	30	20	34	29	8	1	0	597
Subtotal	0	241	3,270	3,951	3,460	1,989	420	410	353	121	38	74	205	159	269	407	582	252	173	180	198	115	41	2	0	16,911
Commercial Exploratory Programs																										
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	241	3,510	5,097	4,729	3,166	1,403	1,117	1,186	768	524	675	890	1,410	4,214	3,941	4,602	4,241	3,606	3,880	3,768	3,307	2,984	2,725	2,700	64,685
INDUSTRIAL																										
Performance Optimization Program	0	0	93	198	254	368	270	317	286	219	235	221	310	2,082	430	205	363	427	540	633	479	428	431	369	885	10,043
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88	76	7	1	1	0	173
Subtotal	0	0	93	198	254	368	270	317	286	219	235	221	310	2,082	430	205	363	427	540	721	555	435	432	370	885	8,961
Discontinued/Completed																										
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	67	299	305	224	419	379	348	49	12	5	0	0	0	0	0	41	0	0	0	0	0	0	0	2,146
High Efficiency Motors	0	24	290	366	283	249	266	288	365	49	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,183
Efficient Motors (QMR)	0	0	0	24	55	21	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	104
Subtotal	0	24	357	689	644	494	689	667	712	99	15	5	0	0	0	0	0	41	0	0	0	0	0	0	0	4,434
	0	24	449	888	897	862	959	984	998	318	250	225	310	2,082	430	205	363	468	540	721	555	435	432	370	885	14,650
EFFICIENCY PROGRAMS SUBTOTAL	158	568	4,391	6,335	6,125	4,598	2,891	2,961	3,137	1,269	789	1,016	1,502	3,990	5,221	5,832	8,091	7,464	7,509	8,390	7,480	5,121	5,937	5,519	6,729	113,023
CUSTOMER SELF-GENERATION PROGRAMS																										
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80	311	329	1,816	361	0	2,898
RATE/LOAD MANAGEMENT PROGRAMS																										
Curtailable Rate Program	0	0	0	91	130	229	79	54	51	36	37	36	10	10	15	18	10	8	10	5	7	8	9	6	4	864
Support Costs	0	380	3,655	4,393	3,121	1,736	2,063	1,657	1,319	1,711	2,435	3,338	3,002	3,798	3,880	4,330	4,602	2,835	3,141	4,133	4,125	3,510	3,874	3,439	2,489	72,965
GRAND TOTAL	158	948	8,046	10,819	9,376	6,564	5,032	4,672	4,507	3,016	3,261	4,390	4,514	7,798	9,116	10,179	12,703	10,307	10,660	12,608	11,923	8,968	11,637	9,325	9,223	189,749

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Program Incentive Costs
(1989/90 - 2013/14)
(000's in 2014 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative 2013/14
RESIDENTIAL																										
Incentive Based																										
Home Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	516	743	1,744	1,426	1,601	1,615	1,238	1,070	856	707	11,516
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110	44	326	815	641	67	91	315	2,410
Lower Income First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	193	0	193
New Home Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	72	138	122	110	122	130	48	12	0	765
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	336	374	373	1,083
Communtity Geothermal Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	197	197
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	401	194	241	195	1,031
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	528	815	1,992	1,591	2,037	2,553	2,409	1,716	1,767	1,788	17,195
Customer Service Initiatives																										
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Discontinued/Completed																										
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,056	1,455	1,437	314	0	0	0	0	4,263
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	33	171	122	73	23	0	0	0	0	422
Outdoor Timer	52	72	63	37	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	255
Res Hot Water	0	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10
Water Heater Rental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	11	6	0	0	0	0	0	41
Retrofit/Demonstration	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
RBB	0	0	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26	0	0	0	0	0	0	0	54
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101	112	76	68	160	135	0	0	652
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Set Top Boxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	169	284	250	273	708	1,160	642	0	0	0	3,485
Subtotal	52	72	100	37	31	0	5	0	0	0	0	0	0	0	0	169	317	1,628	1,974	2,300	1,565	802	135	0	0	9,186
Residential Exploratory Programs																										
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RESIDENTIAL TOTAL	52	72	100	37	31	0	5	0	0	0	0	0	0	0	0	697	1,132	3,620	3,565	4,336	4,118	3,211	1,850	1,767	1,788	26,381
COMMERCIAL																										
Incentive Based																										
Commercial Lighting Program	0	0	0	323	1,626	2,272	2,374	805	478	1,685	622	344	649	406	1,697	3,673	4,900	5,546	5,920	6,446	5,821	5,146	4,741	6,223	5,229	66,925
Commercial Earth Power Program	0	0	0	0	0	0	0	32	157	94	128	75	94	151	378	137	333	464	154	100	285	215	178	190	143	3,309
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	79	124	212	200	252	213	315	387	1,784
Commercial Windows Program	0	0	0	0	0	0	0	52	99	57	45	55	58	120	94	193	286	259	241	373	970	1,182	917	782	501	6,286
Internal Retrofit Program	0	0	0	54	277	402	106	152	111	177	73	213	93	190	531	563	438	604	364	209	906	1,805	627	522	484	8,901
Commercial Custom Measures Program	0	0	0	0	0	0	0	32	0	135	467	55	55	23	100	3	7	45	168	36	134	152	105	47	21	1,584
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	111	89	94	93	212	512	392	1,602
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	114	197	63	217	156	319	202	144	245	1,657
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	840	1,003	3,959	1,512	160	0	0	170	75	20	0	7,738
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	60	10	107	25	29	31	0	262
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	49	52	25	14	4	3	145
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	0	0	0	6
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	10	10	13	25	49	115
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	5	13	0	0	51	71
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	152	0	0	118	117	82	50	521
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	87	3	0	0	0	0	0	89
Subtotal	0	0	0	378	1,902	2,674	2,480	1,072	846	2,150	1,335	742	949	890	3,640	5,573	10,037	8,808	7,605	7,751	8,741	9,527	7,444	8,896	7,555	100,996
Customer Service Initiatives																										
Power Smart for Business PAYS Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Discontinued/Completed																										
Commercial Showerhead	0	0	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
Infrared Heat Lamp	0	0	140	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	140
Livestock Waterer	0	0	0	0	0	21	19	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	52
Roadway Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Air Barrier	0	0	0	0	0	0	0	20	2	3	10	17	12	8	10	3	3	0	5	0	0	0	0	0	0	93
Agricultural Demand Controller	0	0	0	186	64	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	250
Commercial Air Conditioning	0	0	0	0	0	0	0	1	0	0	0	0	4	36	0	134	9	0	0	0	0	0	0	0	0	185
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parking Lot Controllers	0	0	0	0	0	0	0	36	28	130	17	21	51	24	76	84	619	801	511	258	395	484	264	9	0	3,807
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	14	18	3	5	0	0	0	68
Agricultural Heat Pads	0	0	0	0	0	0	0	0	0	52	65	29	39	39	36	52	32	26	36	26	90	77	0	0	0	599
Subtotal	0	0	171	186	64	21	19	69	30	185	91	68	107	107	122	272	663	853	566	303	489	566	264	9	0	5,225
Commercial Exploratory Programs																										
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	171	564	1,966	2,696	2,498	1,142	875	2,335	1,426	810	1,056	997	3,761	5,846	10,700	9,661	8,171	8,053	9,230	10,093	7,708	8,905	7,555	106,221
INDUSTRIAL																										
Performance Optimization Program	0	0	0	0	0	155	259	160	409	203	45	212	783	1,368	866	1,553	1,470	748	2,974	2,105	2,680	2,548	2,662	2,476	1,733	25,411
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	155	259	160	409	203	45	212	783	1,368	866	1,553	1,470	748	2,974	2,105	2,680	2,548	2,662	2,476	1,733	21,201
Discontinued/Completed																										
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	0	39	57	427	700	0	0	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,263
High Efficiency Motors	0	0	40	433	356	260	200	217	316	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,821
Efficient Motors (QMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	40	472	414	686	900	217	316	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,084
	0	0	40	472	414	842	1,159	377	725	243	45	212	783	1,368	866	1,553	1,470	748	2,974	2,105	2,680	2,548	2,662	2,476	1,733	28,494
EFFICIENCY PROGRAMS SUBTOTAL	52	72	310	1,073	2,410	3,538	3,662	1,519	1,600	2,577	1,471	1,022	1,838	2,365	4,628	8,095	13,301	14,029	14,711	14,495	16,028	15,852	12,221	13,149	11,075	161,096
CUSTOMER SELF-GENERATION PROGRAMS																										
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160	1,852	1,789	1,799	1,304	1,396	0	0	0	8,300
RATE/LOAD MANAGEMENT PROGRAMS																										
Curtailable Rate Program	0	0	0	0	544	1,424	1,409	1,404	1,211	1,576	1,957	2,521	3,358	5,070	6,637	6,651	7,425	7,266	7,201	6,973	6,255	6,164	6,097	5,966	6,066	93,172
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRAND TOTAL	52	72	310	1,073	2,954	4,962	5,071	2,923	2,811	4,153	3,428	3,542	5,197	7,435	11,265	14,746	20,886	23,146	23,700	23,266	23,588	23,412	18,317	19,115	17,141	262,568

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Energy Savings (million m3)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	
RESIDENTIAL																
Incentive Based																
New Home Program	0.0	0.0	0.0	0.0	0.0	0.1	0.8	1.5	2.2	2.9	3.6	4.3	5.0	5.7	6.4	
Home Insulation Program	0.8	1.5	2.3	3.0	3.7	4.4	5.1	5.7	6.4	7.1	7.7	8.3	8.9	8.9	8.9	
Water and Energy Saver Program	0.8	1.6	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Affordable Energy Program	1.3	2.6	3.8	4.9	5.7	6.1	6.4	6.5	6.5	6.5	6.4	6.3	6.4	6.2	6.1	
Subtotal	2.9	5.7	8.5	10.3	11.9	13.1	14.7	16.2	17.6	19.0	20.2	21.4	22.8	23.3	23.9	74%
Customer Service Initiatives / Financial Loan Programs																
Power Smart Residential Loan	0.3	0.6	0.9	1.2	1.5	1.9	2.2	2.5	2.8	3.1	3.4	3.7	4.0	4.3	4.6	
Power Smart PAYS Financing	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Residential Earth Power Loan	0.2	0.4	0.6	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.0	2.0	2.0	2.0	2.0	
Subtotal	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	5.8	6.2	6.5	6.8	21%
COMMERCIAL																
Incentive Based																
Commercial Building Envelope - Windows Program	0.4	0.7	1.0	1.2	1.5	1.8	2.0	2.3	2.6	2.9	3.1	3.4	3.7	3.9	4.2	
Commercial Building Envelope - Insulation Program	0.9	1.8	2.6	3.5	4.3	5.2	6.1	6.9	7.8	8.7	9.6	10.5	11.3	12.2	13.1	
Commercial HVAC Program - Boilers	1.0	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7	3.9	4.1	4.3	4.5	4.7	
Commercial HVAC Program - CO2 Sensors	0.1	0.3	0.5	0.8	1.0	1.3	1.7	2.1	2.5	2.9	2.9	2.9	2.9	2.8	2.8	
Commercial HVAC Program - Water Heaters	0.0	0.0	0.1	0.2	0.3	0.4	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.7	0.7	
Commercial Custom Measures Program	0.1	0.2	0.3	0.4	0.6	0.7	0.8	1.0	1.1	1.3	1.4	1.6	1.8	1.9	2.1	
Commercial Building Optimization Program	0.1	0.2	0.5	0.7	0.9	1.2	1.4	1.8	2.1	2.5	2.7	3.0	3.2	3.5	3.7	
New Buildings Program	0.3	0.7	1.2	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Commercial Kitchen Appliance Program	0.2	0.5	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	
Internal Retrofit Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Power Smart Shops	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Subtotal	3.2	6.6	9.4	11.5	13.6	15.9	18.2	20.6	23.0	25.3	27.1	29.0	30.7	32.3	33.9	105%
Customer Service Initiatives / Financial Loan Programs																
Power Smart for Business PAYS Financing	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Subtotal	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0%
INDUSTRIAL																
Natural Gas Optimization Program	1.2	2.4	3.6	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	
Subtotal	1.2	2.4	3.6	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	15%
ENERGY EFFICIENCY SUBTOTAL	7.9	15.8	23.1	28.7	32.8	36.8	41.3	45.7	50.0	54.2	57.7	61.1	64.5	67.0	69.5	214%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																
Bioenergy Optimization Program	0.0	0.7	0.9	1.4	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	0.0	0.7	0.9	1.4	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	5%
FUEL CHOICE																
Fuel Choice	0.0	0.0	0.0	-7.8	-15.5	-23.3	-31.1	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	
FUEL CHOICE SUBTOTAL	0.0	0.0	0.0	-7.8	-15.5	-23.3	-31.1	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	-38.8	-120%
Impacts	8	17	24	22	19	15	12	9	13	17	21	24	27	30	32	100%
Interactive Effects	-1.0	-2.0	-3.0	-3.3	-3.6	-3.8	-3.8	-3.8	-3.9	-4.0	-3.5	-2.9	-2.4	-2.3	-2.2	
Subtotal	7	15	21	19	15	11	8	5	9	13	17	21	25	28	30	
Codes, Standards & Regulations	3	7	11	17	22	28	33	39	45	50	56	62	67	73	78	
POWER SMART 2014 to 2028 Impacts	10	21	32	36	37	39	41	44	54	63	73	83	92	100	108	
POWER SMART SAVINGS TO DATE																
Incentive Based Program Impacts	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	
Customer Service Initiatives Program Impacts	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
Discontinued Programs	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	
Interactive Effects	-7	-5	-5	-5	-6	-6	-6	-6	-6	-5	-5	-4	-4	-4	-3	
Impacts of Codes & Standards (at meter)	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	
TOTAL m3	109	122	133	137	138	140	141	144	153	164	174	185	194	203	211	

NATURAL GAS DSM

APPENDIX C.2

2014 - 2017 Power Smart Plan
Annual Utility Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$6	$19	$39	$27	$0	$0	$0	$0	$0	$0	$0	$0	$91	
Home Insulation Program	$1,346	$1,335	$1,314	$1,242	$1,237	$1,219	$1,174	$1,156	$1,134	$1,080	$1,038	$1,032	$1,016	$83	$0	$15,404	
Water and Energy Saver Program	$1,070	$1,070	$1,070	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,211	
Affordable Energy Program	$622	$567	$2,603	$2,816	$2,654	$2,509	$2,369	$2,474	$2,444	$2,565	$2,470	$2,527	$2,506	$0	$0	$29,126	
Subtotal	$3,037	$2,972	$4,988	$4,065	$3,910	$3,766	$3,571	$3,630	$3,578	$3,645	$3,508	$3,559	$3,521	$83	$0	$47,832	50%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Building Envelope - Windows Program	$873	$578	$395	$398	$398	$398	$398	$402	$402	$402	$402	$402	$402	$402	$402	$6,657	
Commercial Building Envelope - Insulation Program	$1,466	$1,467	$1,352	$1,374	$1,374	$1,374	$1,374	$1,391	$1,391	$1,391	$1,391	$1,391	$1,391	$1,391	$1,391	$20,906	
Commercial HVAC Program - Boilers	$1,127	$1,177	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$2,379	
Commercial HVAC Program - CO2 Sensors	$131	$160	$169	$182	$190	$199	$208	$217	$226	$233	$5	$5	$5	$5	$5	$1,940	
Commercial HVAC Program - Water Heaters	$0	$83	$77	$86	$97	$111	$119	$69	$71	$73	$74	$0	$0	$0	$0	$860	
Commercial Custom Measures Program	$199	$199	$199	$199	$209	$209	$209	$209	$209	$219	$218	$218	$218	$218	$217	$3,151	
Commercial Building Optimization Program	$209	$189	$236	$236	$236	$284	$284	$308	$308	$332	$332	$356	$356	$380	$380	$4,425	
New Buildings Program	$575	$767	$958	$0	$96	$192	$288	$383	$479	$0	$0	$0	$0	$0	$0	$3,738	
Commercial Kitchen Appliance Program	$104	$132	$163	$72	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$471	
Internal Retrofit Program	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$53	
Power Smart Shops	$0	$14	$13	$13	$14	$14	$14	$14	$14	$13	$13	$0	$0	$0	$0	$135	
Subtotal	$4,738	$4,765	$3,568	$2,566	$2,620	$2,787	$2,899	$2,999	$3,106	$2,668	$2,441	$2,378	$2,378	$2,401	$2,401	$44,716	47%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Natural Gas Optimization Program	$575	$575	$575	$575	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,300	
Subtotal	$575	$575	$575	$575	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,300	2%
ENERGY EFFICIENCY SUBTOTAL	$8,350	$8,313	$9,131	$7,206	$6,530	$6,552	$6,469	$6,629	$6,683	$6,314	$5,949	$5,937	$5,899	$2,484	$2,401	$94,848	99%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$25	$467	$65	$163	$64	$64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$848	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$25	$467	$65	$163	$64	$64	$0	$0	$0	$0	$0	$0	$0	$0	$0	$848	1%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Subtotal of Programs	$8,375	$8,780	$9,196	$7,369	$6,594	$6,616	$6,469	$6,629	$6,683	$6,314	$5,949	$5,937	$5,899	$2,484	$2,401	$95,696	100%
Program Support	$1,621	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$24,252	
Contingency	$200	$400	$400	$500	$500	$500	$500	$500	$500	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$10,000	
Total Utility Costs (2014 to 2028)	$10,196	$10,796	$11,212	$9,486	$8,711	$8,733	$8,586	$8,745	$8,800	$8,930	$8,566	$8,554	$8,516	$5,101	$5,018	$129,948	
Total Committed to Date																$102,073	
TOTAL UTILITY COSTS (1989 to 2028)	$10,196	$10,796	$11,212	$9,486	$8,711	$8,733	$8,586	$8,745	$8,800	$8,930	$8,566	$8,554	$8,516	$5,101	$5,018	$232,021	

Note: May not add up due to rounding.

NATURAL GAS DSM

APPENDIX C.3

2014 - 2017 Power Smart Plan
Annual Program Administration Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$6	$19	$39	$27	$0	$0	$0	$0	$0	$0	$0	$0	$91	
Home Insulation Program	$355	$361	$358	$302	$313	$312	$283	$281	$274	$236	$209	$218	$217	$83	$0	$3,802	
Water and Energy Saver Program	$788	$788	$788	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,365	
Affordable Energy Program	$135	$126	$2,201	$2,449	$2,316	$2,197	$2,082	$2,207	$2,196	$2,335	$2,256	$2,328	$2,317	$0	$0	$25,145	
Subtotal	$1,278	$1,275	$3,347	$2,757	$2,649	$2,547	$2,392	$2,488	$2,471	$2,571	$2,464	$2,547	$2,534	$83	$0	$31,403	76%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Building Envelope - Windows Program	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$64	$955	
Commercial Building Envelope - Insulation Program	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$73	$1,095	
Commercial HVAC Program - Boilers	$248	$248	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$571	
Commercial HVAC Program - CO2 Sensors	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$5	$5	$5	$5	$5	$1,129	
Commercial HVAC Program - Water Heaters	$0	$70	$56	$56	$56	$56	$56	$56	$56	$56	$56	$0	$0	$0	$0	$573	
Commercial Custom Measures Program	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$168	$2,524	
Commercial Building Optimization Program	$137	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$117	$1,779	
New Buildings Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Commercial Kitchen Appliance Program	$48	$48	$48	$36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$179	
Internal Retrofit Program	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$53	
Power Smart Shops	$0	$14	$11	$11	$11	$11	$11	$11	$11	$11	$11	$0	$0	$0	$0	$111	
Subtotal	$902	$912	$653	$641	$605	$605	$605	$605	$605	$605	$500	$433	$433	$433	$433	$8,969	22%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Natural Gas Optimization Program	$215	$215	$215	$215	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$860	
Subtotal	$215	$215	$215	$215	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$860	2%
ENERGY EFFICIENCY SUBTOTAL	$2,395	$2,402	$4,215	$3,613	$3,253	$3,152	$2,997	$3,093	$3,075	$3,176	$2,964	$2,980	$2,967	$516	$433	$41,232	100%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$12	$13	$12	$13	$11	$10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$71	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$12	$13	$12	$13	$11	$10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$71	0%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Subtotal of Programs	$2,406	$2,416	$4,226	$3,626	$3,264	$3,162	$2,997	$3,093	$3,075	$3,176	$2,964	$2,980	$2,967	$516	$433	$41,302	100%
Program Support	$1,621	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$1,616	$24,252	
Contingency	$200	$400	$400	$500	$500	$500	$500	$500	$500	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$10,000	
Total Administration Costs (2014 to 2028)	$4,228	$4,432	$6,243	$5,742	$5,381	$5,279	$5,113	$5,209	$5,192	$5,792	$5,581	$5,596	$5,583	$3,133	$3,050	$75,554	
Total Committed to Date																$45,681	
TOTAL ADMINISTRATION COSTS (1989 to 2028)	$4,228	$4,432	$6,243	$5,742	$5,381	$5,279	$5,113	$5,209	$5,192	$5,792	$5,581	$5,596	$5,583	$3,133	$3,050	$121,235	

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Program Incentive Costs
(000's in 2014 $)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Home Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Home Insulation Program	$991	$974	$957	$940	$923	$907	$891	$875	$860	$844	$829	$814	$799	$0	$0	$11,603	
Water and Energy Saver Program	$282	$282	$282	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$845	
Affordable Energy Program	$487	$441	$402	$367	$338	$312	$287	$267	$248	$230	$215	$199	$189	$0	$0	$3,981	
Subtotal	$1,759	$1,697	$1,641	$1,307	$1,261	$1,219	$1,179	$1,142	$1,107	$1,075	$1,043	$1,013	$988	$0	$0	$16,430	30%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Incentive Based																	
Commercial Building Envelope - Windows Program	$809	$514	$331	$335	$335	$335	$335	$339	$339	$339	$339	$339	$339	$339	$339	$5,702	
Commercial Building Envelope - Insulation Program	$1,393	$1,394	$1,279	$1,301	$1,301	$1,301	$1,301	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$1,318	$19,810	
Commercial HVAC Program - Boilers	$879	$929	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,808	
Commercial HVAC Program - CO2 Sensors	$21	$49	$59	$71	$79	$89	$98	$107	$116	$123	$0	$0	$0	$0	$0	$811	
Commercial HVAC Program - Water Heaters	$0	$13	$21	$30	$42	$55	$63	$13	$15	$17	$18	$0	$0	$0	$0	$287	
Commercial Custom Measures Program	$31	$31	$31	$31	$41	$41	$41	$41	$41	$50	$50	$50	$50	$49	$49	$628	
Commercial Building Optimization Program	$72	$72	$119	$119	$119	$167	$167	$191	$191	$215	$215	$238	$238	$262	$262	$2,646	
New Buildings Program	$575	$767	$958	$0	$96	$192	$288	$383	$479	$0	$0	$0	$0	$0	$0	$3,738	
Commercial Kitchen Appliance Program	$57	$84	$115	$36	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$292	
Internal Retrofit Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart Shops	$0	$1	$2	$3	$3	$3	$3	$3	$3	$3	$2	$0	$0	$0	$0	$24	
Subtotal	$3,836	$3,853	$2,915	$1,925	$2,015	$2,182	$2,294	$2,394	$2,501	$2,063	$1,942	$1,945	$1,945	$1,968	$1,968	$35,747	66%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Natural Gas Optimization Program	$360	$360	$360	$360	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,440	
Subtotal	$360	$360	$360	$360	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,440	3%
ENERGY EFFICIENCY SUBTOTAL	$5,955	$5,910	$4,916	$3,593	$3,276	$3,400	$3,473	$3,536	$3,608	$3,138	$2,985	$2,957	$2,932	$1,968	$1,968	$53,617	99%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$13	$453	$53	$151	$53	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$777	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$13	$453	$53	$151	$53	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$777	1%
FUEL CHOICE																	
Fuel Choice	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
FUEL CHOICE SUBTOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Subtotal of Programs	$5,968	$6,364	$4,970	$3,744	$3,330	$3,454	$3,473	$3,536	$3,608	$3,138	$2,985	$2,957	$2,932	$1,968	$1,968	$54,394	100%
Total Incentive Costs (2014 to 2028)	$7,590	$7,980	$6,586	$5,360	$4,946	$5,070	$5,089	$5,152	$5,224	$4,754	$4,601	$4,574	$4,549	$3,585	$3,584	$78,646	
Total Committed to Date																$58,768	
TOTAL INCENTIVE COSTS (1989 to 2028)	$7,590	$7,980	$6,586	$5,360	$4,946	$5,070	$5,089	$5,152	$5,224	$4,754	$4,601	$4,574	$4,549	$3,585	$3,584	$137,414	

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Energy Savings
(Savings to Date)
(million m3)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Benchmark 2028/29
RESIDENTIAL														
incentive Based														
Home Insulation Program	0.00	0.00	0.00	0.00	0.30	2.15	3.85	5.58	7.59	9.01	10.15	11.26	12.00	12.00
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.69	2.32	3.51	4.62	5.72	5.72
New Home Program	0.00	0.00	0.00	0.03	0.08	0.15	0.23	0.34	0.41	0.52	0.55	0.55	0.55	0.55
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	1.78	3.15	3.84	3.84
Subtotal	0.00	0.00	0.00	0.03	0.39	2.30	4.10	5.98	8.69	12.68	15.99	19.58	22.11	22.11
CUSTOMER SERVICE INITIATIVES														
Power Smart Residential Loan Program	1.23	2.14	3.51	5.57	7.80	9.56	11.30	12.29	13.93	14.27	14.60	14.90	15.19	15.19
Residential Earth Power Program	0.00	0.05	0.15	0.50	0.79	0.97	1.31	1.45	1.67	2.10	2.39	2.41	2.42	2.42
ecoEnergy	0.00	0.13	0.39	1.25	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
Solar H2O Heater	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Smart PAYS Financing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	1.23	2.31	4.04	7.32	10.91	12.85	14.94	16.05	17.93	18.69	19.31	19.63	19.94	19.94
DISCONTINUED/COMPLETED														
Thermostat	0.00	0.00	0.00	0.00	0.00	0.11	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.61	2.60	4.04	5.77	6.93	6.96	6.96	6.96	6.96	6.96
Power Smart Energy Manager	-0.01	0.05	0.18	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
R2000 House	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Subtotal	0.00	0.07	0.21	0.35	0.95	3.06	4.56	6.29	7.44	7.48	7.48	7.48	7.48	7.48
RESIDENTIAL TOTAL	1.23	2.38	4.25	7.70	12.25	18.21	23.59	28.32	34.06	38.85	42.77	46.69	49.52	49.52
COMMERCIAL														
Incentive Based														
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.29	1.05	2.15	3.24	5.37	6.83	7.87	9.05	9.05
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.03	0.11	0.23	0.50	0.83	1.33	1.59	1.89	1.89
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.17	0.26	1.38	1.41	1.41
City of Winnipeg Power Smart Agreement	0.00	0.05	0.13	0.17	0.56	0.67	0.67	0.67	0.71	0.78	0.82	0.82	0.82	0.82
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Internal Retrofit Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.05	0.07	0.08	0.09	0.09
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.04	0.04	0.04	0.04
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.24	0.36	0.36	0.50	0.71	0.35
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35	2.76	2.80	2.80
HVAC - CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.83	0.83
HVAC - Boilers	0.00	0.00	0.00	0.00	0.00	0.42	2.52	4.81	6.20	6.20	7.17	8.38	9.18	9.18
Subtotal	0.00	0.05	0.13	0.17	0.56	1.41	4.36	8.00	11.02	13.81	17.23	23.62	26.82	26.46
DISCONTINUED/COMPLETED														
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.83	1.12	2.11	2.37	2.37	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.83	1.12	2.11	2.37	2.37	0.00	0.00	0.00	0.00
CUSTOMER SERVICE INITIATIVES														
Power Smart for Business PAYS Financing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.02	-0.02
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.02	-0.02
COMMERCIAL SUBTOTAL	0.00	0.05	0.13	0.17	0.56	2.24	5.48	10.11	13.39	16.18	17.23	23.62	26.81	26.44
INDUSTRIAL														
Industrial Natural Gas Optimization	0.00	0.00	0.00	0.00	0.00	0.00	1.69	3.85	4.94	8.04	10.53	12.46	14.03	14.03
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	1.69	3.85	4.94	8.04	10.53	12.46	14.03	14.03
EFFICIENCY PROGRAMS SUBTOTAL	1.23	2.44	4.38	7.88	12.81	20.45	30.76	42.28	52.40	63.07	70.53	82.77	90.36	90.00
CUSTOMER SELF-GENERATION PROGRAMS														
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE/LOAD MANAGEMENT PROGRAMS														
Interactive Effects	0.00	0.00	0.00	-1.20	-2.57	-3.00	-3.79	-5.86	-8.53	-9.96	-10.59	-11.21	-10.38	-3.30
Subtotal after Interactive Effects	1.23	2.43	4.38	6.67	10.24	17.46	26.97	36.42	43.86	53.12	59.94	71.56	79.97	86.69
Codes, Standards & regulations	0.35	0.71	1.12	1.55	1.97	2.37	2.73	2.97	3.52	4.40	9.87	13.23	15.90	15.90
Power Smart 2013 to 2027 Impacts	1.58	3.14	5.50	8.23	12.21	19.83	29.70	39.39	47.38	57.52	69.81	84.79	95.87	102.59

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Utility Costs
(2001/02 - 2013/14)
(000's in 2014 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative Total 2013/14
RESIDENTIAL														
Incentive Based														
Home Insulation Program	0	0	0	0	417	2,034	3,258	3,007	3,198	2,397	2,220	1,465	1,178	19,174
Lower Income Energy Efficiency Program	0	0	0	0	88	0	181	226	808	858	868	666	3,084	6,778
New Home Program	0	14	83	102	68	103	151	0	94	117	67	5	0	804
Water and Energy Saver Program	0	0	0	0	0	0	0	0	44	737	1,081	805	1,095	3,762
Subtotal	0	14	83	102	572	2,137	3,591	3,233	4,144	4,109	4,235	2,941	5,357	30,518
CUSTOMER SERVICE INITIATIVES														
Power Smart Residential Loan Program	468	121	54	-6	16	194	-24	-117	-712	-754	-575	-670	458	-1,546
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	38	55	35	129
ecoEnergy	269	311	314	376	-11	692	531	-118	614	410	495	-120	0	3,765
Solar H2O Heater	0	0	0	0	0	0	0	0	2	0	0	0	0	2
Subtotal	738	432	368	370	6	887	507	-235	-96	-344	-41	-735	493	2,349
DISCONTINUED/COMPLETED														
Thermostat	0	0	0	0	0	213	144	42	1	0	0	0	0	399
High Efficiency Furnace & Boiler	0	0	0	0	644	1,457	2,320	3,461	1,663	33	0	0	0	9,579
Subtotal	0	0	0	0	644	1,670	2,464	3,503	1,664	33	0	0	0	9,978
RESIDENTIAL EXPLORATORY														
Residential Solar	0	0	0	0	0	0	0	0	0	8	9	0	0	16
RESIDENTIAL TOTAL	738	446	451	472	1,222	4,694	6,562	6,501	5,711	3,806	4,202	2,206	5,850	42,862
COMMERCIAL														
Incentive Based														
Commercial Insulation Program	0	0	0	0	0	463	903	1,105	1,349	2,371	1,848	1,150	1,794	10,983
Commercial Windows Program	0	0	0	0	0	142	307	505	846	1,072	1,153	827	927	5,778
Commercial Custom Measures Program	0	0	0	0	0	0	0	0	152	165	167	524	295	1,303
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	17	60	31	50	28	11	197
Power Smart Shops	0	0	0	0	0	0	1	16	87	102	12	0	0	219
Commercial Building Optimization Program	0	0	0	0	84	253	173	172	254	220	125	95	127	1,503
New Buildings Program	0	0	0	0	0	0	0	156	117	208	209	1,083	779	2,552
Commercial Boiler Program	0	0	0	0	116	669	1,812	1,508	1,216	1,319	966	1,224	891	9,719
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	38	29	67
Power Smart Energy Manager Program	0	0	0	0	0	0	130	103	77	0	54	0	0	364
Power Smart for Business PAYS Financing	0	0	0	0	0	0	0	0	0	0	0	0	153	153
Subtotal	0	0	0	0	200	1,526	3,326	3,583	4,157	5,487	4,583	4,969	5,006	32,838
DISCONTINUED/COMPLETED														
Spray Valves	0	0	0	0	0	141	60	133	29	22	2	0	0	388
Subtotal	0	0	0	0	0	141	60	133	29	22	2	0	0	388
COMMERCIAL EXPLORATORY														
Commercial Water Heater Program	0	0	0	0	0	0	0	0	24	33	15	0	0	72
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	5	11	0	0	16
	0	0	0	0	0	0	0	0	24	38	26	0	0	88
COMMERCIAL TOTAL	0	0	0	0	200	1,668	3,387	3,716	4,210	5,547	4,611	4,970	5,006	33,314
INDUSTRIAL														
Industrial Natural Gas Optimization Program	0	0	0	0	113	41	317	365	649	753	746	782	696	4,460
Subtotal	0	0	0	0	113	41	317	365	649	753	746	782	696	4,460
EFFICIENCY PROGRAMS SUBTOTAL	738	446	451	472	1,535	6,402	10,265	10,582	10,570	10,106	9,559	7,957	11,552	80,635
CUSTOMER SELF-GENERATION PROGRAMS														
BioEnergy Optimization Program	0	0	0	0	0	0	15	9	0	0	0	0	0	23
Support Costs	1,084	739	681	990	1,448	2,803	2,221	2,125	2,167	1,469	1,905	2,211	1,570	21,415
GRAND TOTAL	1,822	1,185	1,132	1,462	2,983	9,205	12,501	12,716	12,737	11,575	11,464	10,168	13,121	102,073

Note: May not add up due to rounding.

2014 - 2027 Power Smart Plan
Annual Program Admininstration Costs
(2001/02 - 2013/14)
(000's in 2014 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative Total 2013/14
RESIDENTIAL														
Incentive Based														
Home Insulation Program	0	0	0	0	189	582	835	652	512	536	547	191	194	4,239
Lower Income Energy Efficiency Program	0	0	0	0	87	0	155	141	199	983	389	234	772	2,961
New Home Program	0	14	83	83	23	34	54	0	16	0	18	1	0	326
Water and Energy Saver Program	0	0	0	0	0	0	0	0	44	136	627	564	900	2,271
Subtotal	0	14	83	83	299	616	1,044	793	771	1,655	1,582	991	1,867	9,797
CUSTOMER SERVICE INITIATIVES														
Power Smart Residential Loan Program	468	121	54	-6	16	194	-24	-117	-712	-754	-575	-670	458	-1,546
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	38	55	35	129
ecoEnergy	269	311	314	376	-11	692	531	-118	614	410	495	-120	0	3,765
Solar H2O Heater	0	0	0	0	0	0	0	0	2	0	0	0	0	2
Subtotal	738	432	368	370	6	887	507	-235	-96	-344	-41	-736	493	2,349
DISCONTINUED/COMPLETED														
Thermostat	0	0	0	0	0	121	104	20	1	0	0	0	0	245
High Efficiency Furnace & Boiler	0	0	0	0	291	319	491	389	212	18	0	0	0	1,720
Subtotal	0	0	0	0	291	440	595	408	213	18	0	0	0	1,965
RESIDENTIAL EXPLORATORY														
Residential Solar	0	0	0	0	0	0	0	0	0	8	9	0	0	0
RESIDENTIAL TOTAL	738	446	451	454	595	1,943	2,146	966	888	1,337	1,549	256	2,360	14,111
COMMERCIAL														
Incentive Based														
Commercial Insulation Program	0	0	0	0	0	82	83	189	191	236	284	119	121	1,305
Commercial Windows Program	0	0	0	0	0	90	94	133	153	181	183	99	100	1,032
Commercial Custom Measures Program	0	0	0	0	0	0	0	0	62	64	97	98	108	430
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	9	25	11	29	20	4	99
Power Smart Shops	0	0	0	0	0	0	1	16	87	100	12	0	0	216
Commercial Building Optimization Program	0	0	0	0	84	253	173	126	168	164	84	71	78	1,201
New Buildings Program	0	0	0	0	0	0	0	156	117	129	131	349	325	1,208
Commercial Boiler Program	0	0	0	0	116	313	325	274	377	280	303	312	283	2,582
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	26	16	42
Power Smart Energy Manager Program	0	0	0	0	0	0	130	101	77	0	54	0	0	362
Power Smart for Business PAYS Financing	0	0	0	0	0	0	0	0	0	0	0	0	112	112
Subtotal	0	0	0	0	200	737	805	1,005	1,255	1,165	1,179	1,093	1,148	8,588
DISCONTINUED/COMPLETED														
Spray Valves	0	0	0	0	0	58	34	28	19	3	2	0	0	143
Subtotal	0	0	0	0	0	58	34	28	19	3	2	0	0	143
COMMERCIAL EXPLORATORY														
Commercial Water Heater Program	0	0	0	0	0	0	0	0	24	33	15	0	0	72
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	11	0	0	0
	0	0	0	0	0	0	0	0	24	33	26	0	0	72
COMMERCIAL TOTAL	0	0	0	0	200	795	839	1,033	1,298	1,200	1,206	1,093	1,148	8,802
INDUSTRIAL														
Industrial Natural Gas Optimization Program	0	0	0	0	113	41	101	95	179	126	182	253	212	1,302
Subtotal	0	0	0	0	113	41	101	95	179	126	182	253	212	1,302
EFFICIENCY PROGRAMS SUBTOTAL	738	446	451	454	908	2,779	3,086	2,094	2,365	2,664	2,937	1,602	3,720	24,243
CUSTOMER SELF-GENERATION PROGRAMS														
BioEnergy Optimization Program	0	0	0	0	0	0	15	9	0	0	0	0	0	23
Support Costs	1,084	739	681	990	1,448	2,803	2,221	2,125	2,167	1,469	1,905	2,211	1,570	21,415
GRAND TOTAL	1,822	1,185	1,132	1,444	2,356	5,582	5,322	4,228	4,532	4,133	4,842	3,813	5,290	45,681

Note: May not add up due to rounding.

2014 - 2017 Power Smart Plan
Annual Program Incentive Costs
(2001/02 - 2013/14)
(000's in 2014 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Interim Estimate 2013/14	Cumulative Total 2013/14
RESIDENTIAL														
Incentive Based														
Home Insulation Program	0	0	0	0	228	1,452	2,423	2,356	2,686	1,862	1,673	1,273	984	14,936
Lower Income Energy Efficiency Program	0	0	0	0	0	0	25	372	1,487	1,277	478	432	2,311	6,382
New Home Program	0	0	0	18	45	69	97	0	78	90	50	4	0	452
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	439	453	241	195	1,328
Subtotal	0	0	0	18	273	1,521	2,545	2,727	4,251	3,668	2,654	1,950	3,490	23,097
CUSTOMER SERVICE INITIATIVES														
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DISCONTINUED/COMPLETED														
Thermostat	0	0	0	0	0	92	40	22	0	0	0	0	0	154
High Efficiency Furnace & Boiler	0	0	0	0	353	1,138	1,829	3,073	1,451	15	0	0	0	7,859
Subtotal	0	0	0	0	353	1,230	1,869	3,095	1,451	15	0	0	0	8,013
RESIDENTIAL EXPLORATORY														
Residential Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RESIDENTIAL TOTAL	0	0	0	18	626	2,751	4,414	5,822	5,702	3,683	2,654	1,950	3,490	31,110
COMMERCIAL														
Incentive Based														
Commercial Insulation Program	0	0	0	0	0	381	820	916	1,158	2,135	1,564	1,032	1,673	9,678
Commercial Windows Program	0	0	0	0	0	52	213	372	693	891	970	728	827	4,746
Commercial Custom Measures Program	0	0	0	0	0	0	0	0	90	101	70	426	186	873
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	9	34	20	21	8	6	99
Power Smart Shops	0	0	0	0	0	0	0	0	1	2	0	0	0	3
Commercial Building Optimization Program	0	0	0	0	0	0	0	46	86	56	40	25	49	302
New Buildings Program	0	0	0	0	0	0	0	0	0	79	78	734	453	1,344
Commercial Boiler Program	0	0	0	0	0	356	1,487	1,234	839	1,043	662	912	608	7,142
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	12	13	25
Power Smart Energy Manager Program	0	0	0	0	0	0	0	2	0	0	0	0	0	2
Power Smart for Business PAYS Financing	0	0	0	0	0	0	0	0	0	0	0	0	41	41
Subtotal	0	0	0	0	0	789	2,521	2,578	2,902	4,327	3,405	3,876	3,858	24,255
DISCONTINUED/COMPLETED														
Spray Valves	0	0	0	0	0	84	27	105	10	20	0	0	0	245
Subtotal	0	0	0	0	0	84	27	105	10	20	0	0	0	245
COMMERCIAL EXPLORATORY														
Commercial Water Heater Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COMMERCIAL TOTAL	0	0	0	0	0	872	2,547	2,683	2,912	4,346	3,405	3,876	3,858	24,500
INDUSTRIAL														
Industrial Natural Gas Optimization Program	0	0	0	0	0	0	216	270	469	627	564	529	483	3,157
Subtotal	0	0	0	0	0	0	216	270	469	627	564	529	483	3,157
EFFICIENCY PROGRAMS SUBTOTAL	0	0	0	18	626	3,623	7,177	8,775	9,083	8,656	6,622	6,355	7,831	58,768
CUSTOMER SELF-GENERATION PROGRAMS														
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRAND TOTAL	0	0	0	18	626	3,623	7,177	8,775	9,083	8,656	6,622	6,355	7,831	58,768

Note: May not add up due to rounding.

Appendix E - Program Evaluation Criteria

Manitoba Hydro's Power Smart programs take into account the underlying differences in the electricity and natural gas industries and the nature of the programs evaluated. Power Smart programs are assessed annually to ensure the individual programs as well as the overall portfolio of programs are cost-effective and meeting intended market transformation objectives and targets.

Nature of Electricity and Natural Gas Markets

The nature of the electricity and natural gas markets are similar, however unique differences exist and need to be considered in Manitoba Hydro's Power Smart initiative.

For electricity, lower consumption in Manitoba and lower utility revenue is offset by higher revenues realized by selling the conserved energy in the export market. Lower electricity consumption also defers the need to invest in new transmission facilities that would be required to meet future domestic demand. Load management and certain types of demand response initiatives are also unique elements of electricity markets (e.g. short term price volatility creates opportunities for cost-effective load management and demand response initiatives). The combined effect results in an economic case for Manitoba Hydro to aggressively pursue electricity DSM in Manitoba.

With natural gas, lower consumption in Manitoba is offset by lower natural gas purchases from Alberta. In general, this is a one-to-one relationship as Manitoba Hydro passes the cost of primary natural gas and transportation through to its customers with no mark up on the commodity. Load management opportunities are generally not available in the natural gas market as these operational issues are handled through natural gas storage facilities.

Program Categories

Customer Service Programs

Customer service programs are those programs offered as part of the overall Power Smart initiative that represent the customer service levels that would be expected of a utility. Customer service programs and services are assessed by the aggregate value realized by both the Corporation's customers and the Corporation. These assessments are undertaken on an ongoing basis and require a qualitative evaluation of the benefits. Service levels are then adjusted accordingly.

Cost-Recovery Programs

Cost-recovery programs are those programs where the cost associated with the program is recovered from participating customers through fees or charges (e.g. interest rates). The cost-effectiveness of these programs is assessed annually with fees or charges adjusted accordingly.

Financial Loan Programs

Financial Loan Programs assists participating customers in the installation and/or upgrade of energy efficient measures by offering low interest financing opportunities.

Incentive Based Programs

Incentive based programs are those programs where Power Smart uses a financial incentive to encourage customer participation. Assessments provide feedback on the success and cost-effectiveness of individual programs and the Power Smart portfolio. The results of these assessments drive program design and strategy modifications.

Energy Efficient Codes and Standards

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the adoption of energy efficient codes and standards as it ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance.

Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees (e.g. Manitoba Hydro representatives often chair committees). The focus of Manitoba Hydro's efforts on these committees is towards developing new energy efficient technologies, developing energy efficient codes and standards and facilitating market acceptance of new technologies and building design practices.

Economic Effectiveness Metrics

Manitoba Hydro uses a number of cost effective metrics to assess energy efficient opportunities, including whether to pursue an opportunity, how aggressively an opportunity will be pursued, effectiveness of program design options and the relative investment from ratepayers and participants. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

Quantitative assessments include using the following cost effective metrics:

Integrated Metrics

- Societal Cost (SC);
- Total Resource Cost (TRC);
- Total Resource Cost NPV (TRC NPV);
- Levelized Resource Cost (LRC)

Utility Metrics

- Rate Impact Measure Cost (RIM);
- Net Utility Benefit (NUB);
- Utility Net Present Value (Utility NPV)
- Levelized Utility Cost (LUC);

Customer Metrics

- Simple Customer Payback calculation;
- Participating Customer Cost (PC); and
- Participating Customer Cost Net Present Value (PC NPV).

Integrated Metrics

Societal Cost (SC)

The Societal Cost (SC) metric measures the net economic benefit as measured by the TRC, plus additional indirect benefits such the avoided environmental or societal externalities (e.g. reduced health care costs, increase productivity, employment) and "non-priced" benefits enjoyed by participants (improved comfort, improved heath).

$$SC = \frac{(PV\ (\text{Marginal Benefits})\ x\ 1.10) + PV\ (\text{Measurable Non-Energy benefits})}{PV\ (\text{Total Program Admin Costs} + \text{Incremental Product Costs})}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities)

- Measurable non-energy benefits (e.g. water savings);

- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);

- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;

- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Total Resource Cost (TRC)

The Total Resource Cost (TRC) metric assesses whether the benefits that are associated with an energy efficiency program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs with any economic transfers between the Corporation and the participating customer being excluded.

In general, if program offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels) or targeting low participation market sectors (e.g. lower income). The Total Resource Cost metric is defined as follows:

$$\text{TRC} = \frac{\text{PV (Marginal Benefits) + PV (Measurable Non-Energy Benefits)}}{\text{PV (Total Program Admin Costs + Incremental Product Costs)}}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities);
- Measurable non-energy benefits (e.g. water savings);
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Total Resource Cost Net Present Value (TRC NPV)

The Total Resource Cost Net Present Value (TRC NPV) calculation reveals if the economic value of the benefits that are associated with an energy efficiency program are greater than the costs.

$$\text{TRC NPV} = \text{(PV (Marginal Benefits) + PV (Measurable Non-Energy Benefits))} - \text{PV (Total Program Admin Costs + Incremental Product Costs)}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Levelized Resource Cost (LRC)

The Levelized Resource Cost (LRC) is used to determine the overall economic resource cost of energy saved through an energy efficiency program. The LRC provides a levelized cost of energy saved per unit over a fixed time period. The Levelized Resource Cost is defined as follows:

$$LRC = \frac{\text{PV (Incremental Product Costs + Total Program Admin Costs)}}{\text{PV (Energy)}}$$

Where:

- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;

- Energy includes the annual energy savings.

Utility Metrics

Rate Impact Measure Cost(RIM)

The Rate Impact Measure (RIM) metric is used to provide an indication of the long term impact of an energy efficient program on energy rates. The metric is a benefit/cost ratio that represents the economic impact of a program from the ratepayer's perspective. All program related savings and costs incurred by the utility, including revenue loss and incentive payments, are taken into account in this assessment. The Rate Impact Measure metric is defined as follows:

$$\text{RIM} = \frac{\text{PV (Utility Marginal Benefits)}}{\text{PV (Revenue Loss + Utility Program Admin Costs + Incentives)}}$$

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities);
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs;
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions);
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

Net Utility Benefit (NUB)

The Net Utility Benefit (NUB) metric is used to measure the energy saving benefits to the utility net of any revenue losses. Marginal benefits, after deductions from lost revenue are compare to the cost incurred by the by the utility. The Net Utility Benefit metric is defined as follows:

$$\text{NUB} = \frac{\text{PV (Utility Marginal Benefits) - PV (Revenue Loss)}}{\text{PV (Utility Program Admin Costs + Incentives)}}$$

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities);
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs;
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions);
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

Utility Net Present Value (Utility NPV)

The Utility Net Present Value (Utility NPV) calculation reveals from the Utility's perspective, if the economic value of the benefits that are associated with an energy efficiency program are greater than the costs.

$$\text{Utility NPV} = \text{PV (Marginal Benefits – Revenue Loss)} - \text{PV (Utility Program Admin Costs + Incentives)}$$

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities);
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs;
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions);
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

Levelized Utility Cost (LUC)

The Levelized Utility Cost (LUC) is used to provide an economic cost value for the energy saved through an energy efficiency program. The LUC provides the total cost of the conserved energy based upon the utility's investment on behalf of the ratepayer on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different timeframes. The Levelized Utility Cost is defined as follows:

$$\text{LUC} = \frac{\text{PV (Utility Program Admin Costs + Incentives)}}{\text{PV (Energy)}}$$

Where:

- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives includes the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure;
- Energy includes the annual energy savings.

Customer Metrics

Simple Customer Payback Calculation (Payback)

The Simple Customer Payback calculation provides the simple payback of implementing an energy efficient opportunity for customers. This value outlines the amount of time required before the customer recovers the incremental product cost. The value is useful in projecting customer participation rates for energy efficient opportunities. The Customer Payback is defined as follows:

$$CP = \frac{\text{Participant Costs - Incentives}}{\text{Annual Bill Reductions}}$$

Where:

- Participant Costs includes the participant's total incremental cost associated with implementing the energy efficient opportunity, which is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.
- Incentives includes funds provided by Manitoba Hydro and external parties to the participant associated with implementing the energy efficient opportunity;
- Annual Bill Reductions include the first year dollar reductions in the customer's electricity, natural gas, and water bills.

Participating Customer Cost (PC)

The Participating Customer Cost (PC) metric evaluates from a customer perspective if the benefits that are associated with an energy efficiency program are greater than the costs over the life of the measure. The Participating Customer Cost is defined as follows:

$$PC = \frac{\text{PV (Incentives + Revenue Loss)}}{\text{PV (Incremental Product Costs)}}$$

Where:

- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy and measurable non-energy (i.e. water) bill reductions);
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Participating Customer Cost Net Present Value (PC NPV)

The Participating Customer Cost Net Present Value (PC NPV) calculation reveals from the customer's perspective, if the economic value of the benefits that are associated with an energy efficiency program are greater than the costs over the life of the measure.

PC NPV = PV (Incentives + Revenue Loss) - PV (Incremental Product Costs)

Where:

- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy and measurable non-energy (i.e. water) bill reductions);
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

Other DSM Program Assumptions

Market Transformation

Market transformation is a strategic intervention to achieve a lasting, significant share of energy efficient products and services in targeted markets. Manitoba Hydro's Power Smart strategy focuses on creating a sustainable market change where energy efficient technologies and practices become the market standard.

However, market transformation is difficult to measure. Manitoba Hydro has made significant progress in developing specific methodologies for measuring its impacts. Wherever possible, Manitoba Hydro has attempted to obtain sales/technology specific data to calculate a program's true effect. Difficulties arise in 1) obtaining sales data for areas outside of Manitoba for comparison purposes and in 2) obtaining sales information for Manitoba that fall outside of Power Smart program participation. In some instances, qualitative information is used to determine a program's impact on the market. Manitoba Hydro plans to continue work to further quantify and report on the influence of market transformation within the Manitoba marketplace.

Participant Reinvestment

Participant reinvestment is a marketing assumption which measures the program's influence on a participant's decision to repurchasing the energy efficient technology once the initial product life of the energy efficient technology has ended.

Interactive Effects

Interactive effects are related to the impacts of implementing certain electric efficiency opportunities. As a consequence of implementing a more efficient technology, less heat is often produced. The interactive effect refers to the offsetting need to supplement heat as a result of implementing the energy efficient technology. For example, a CFL emits less heat than a traditional incandescent light bulb; therefore it will take more natural gas to heat the area after the CFL is installed. With the creation of natural gas DSM, electric DSM programs are required to quantify increases in natural gas usage due to interactive effects.

2014-17 Power Smart Plan | Supplemental Report 15yr (2014 to 2029)

2012-2013
Power Smart Annual Review

Power Smart Planning, Evaluation & Research Department
Customer Care & Energy Conservation Business Unit

Approved May 13th, 2014

EXECUTIVE SUMMARY

The 2012/13 Power Smart Annual Review reports the energy and demand savings, customer energy cost savings, customer participation and associated greenhouse gas emission reductions achieved through Manitoba Hydro's Power Smart initiative, including an assessment against the 2012/13 planned targets outlined in the 2012 Base DSM Forecast.

The Power Smart initiative, including persisting savings, has achieved 2,269 GW.h and 637 MW in electric savings (at generation), 84 million cubic metres in natural gas savings and 1,691 thousand tonnes of greenhouse gas emission reductions.

The electric savings resulting from the Power Smart initiative, including persisting savings, equate to nearly a third of Winnipeg's residential and commercial power needs. The natural gas savings, including persisting savings, equate to 1.3 times the residential and commercial natural gas needs of Brandon. Together, the electric and natural gas savings equate to taking an estimated 388 thousand cars off the road for a year.

Overall, 2012/13 was a successful year for Manitoba Hydro's Power Smart portfolio. In 2012/13 alone, the electric Power Smart program achieved 332 GW.h and 221 MW in electric savings (at generation), which exceeded the planned savings of 173 GW.h and 200 MW. The natural gas Power Smart program achieved savings of 14.6 million cubic metres which was above the planned target of 10.0 million cubic metres.

Total Power Smart expenditures in 2012/13 were $44 million, which consisted of $27 million from the Power Smart electric budget, $10 million from the Power Smart natural gas budget, $5 million from the Affordable Energy Fund and $2 million from the Furnace Replacement Budget.

To date, $481 million (nominal dollars) have been invested in the Power Smart initiative, $375 million from the Power Smart electric budget, $79 million from the Power Smart natural gas budget, $21 million from the Affordable Energy Fund and $6 million from the Furnace Replacement Budget.

The customer bill reduction due to 2012/13 Power Smart results, including persisting savings, amounts to an annual reduction of $115 million, with $88 million in reduced electricity bills and $28 million in reduced natural gas bills. By customer sector, $37 million was saved in the residential sector, $37 million in the commercial sector and $42 million in the industrial sector. The customer bill reduction relates only to incentive-based programs and DSM support programs.

Cumulative customer bill reduction is approximately $801 million, consisting of $660 million on electric bills and $141 million on natural gas bills.

Including support costs, the total resource cost (TRC) ratio for electric incentive-based programs was 3.6, the rate impact measure (RIM) ratio was 1.2, the levelized utility cost (LUC) was 1.0¢/kW.h and the levelized resource cost (LRC) was 2.0¢/kW.h . Including support costs and interactive effects, the TRC ratio for natural gas incentive-based programs was 1.2, the RIM ratio was 0.6, the LUC was 11.3¢/m^3 and the LRC was 23.4¢/m^3.

The combined TRC ratio for electric and natural gas incentive-based programs, including support costs and interactive effects, was 2.7.

Awareness of the Power Smart brand continues to remain high with 95% of Manitoba respondents saying they recognize the brand name. Customers continue to report the strongest association between Power Smart and energy efficiency, with the vast majority (83%) of respondents agreeing that the brand projects that message. Customers continue to strongly agree that the Power Smart brand is greatly associated with 'Helping customers save money on their energy bills', with 75% of respondents providing a 7 or higher out of 10, and one-third (32%) saying they had participated in a Manitoba Hydro Power Smart program.

This report utilizes an integrated approach to evaluating the net energy savings achieved through the Power Smart initiative. The results reported are due to combined electric and natural gas energy conservation efforts. In this regard, increased natural gas consumption resulting from electricity efficiency efforts (interactive effects) are netted against savings achieved directly through natural gas conservation.

2012/13 Electricity Results

In 2012/13 alone, the Power Smart portfolio realized 332 GW.h and 221 MW of electric savings, 92% and 11% above their respective savings targets. The following tables outline the electricity savings achieved by the Power Smart portfolio and associated costs during 2012/13, and provide a comparison between achieved results and planned targets.

Exhibit E.1
Annual GW.h Savings (at generation) - Power Smart Portfolio

	2012/13 Actual	2012/13 Plan^	Total*
INCENTIVE-BASED PROGRAMS	256	104	1,612
CODES & STANDARDS	75	66	628
DSM SUPPORT PROGRAMS	1	3	29
OVERALL IMPACT	332	173	2,269

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

Exhibit E.2

Annual Average Winter MW Savings (at generation) - Power Smart Portfolio

	2012/13 Actual	2012/13 Plan^	Total*
INCENTIVE-BASED PROGRAMS	201	184	477
CODES & STANDARDS	19	16	150
DSM SUPPORT PROGRAMS	1	1	10
OVERALL IMPACT	221	200	637

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.
MW savings are based on the average of the winter AM & PM system peak savings.
For the Curtailable Rates Program, MW savings reported is expected curtailable load on system at the time a curtailment occurs.

Exhibit E.3

2012/13 Power Smart Portfolio Electricity Costs

Power Smart Portfolio	2012/13
	millions of dollars
INCENTIVE-BASED PROGRAMS	
Efficiency Programs	18.0
Customer Self-Generation Programs	0.3
Rate/Load Management Programs	5.8
	24.1
SUPPORT COSTS, DSM SUPPORT PROGRAMS & STANDARDS	3.3
TOTAL ELECTRICITY PROGRAM COSTS	27.4

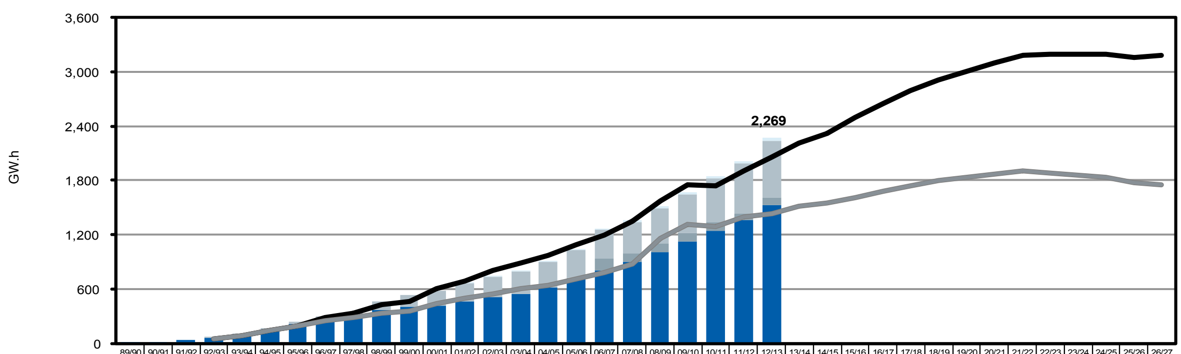
Note: Figures may not add due to rounding.

Total Electricity Results (2012/13 Results & Persisting Savings)

Cumulatively, the Power Smart portfolio has saved a total of 2,269 GW.h and 637 MW, which were 10% and 6% more than planned to the end of 2012/13. Cumulative savings to date represent 71% and 74% of the forecasted energy and demand savings at the benchmark year of 2026/27. To date $375 million has been invested in Power Smart electric activities.

The following graphs present the cumulative energy and average winter demand savings achieved and corresponding targets.

Exhibit E.4
Electric Energy Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation

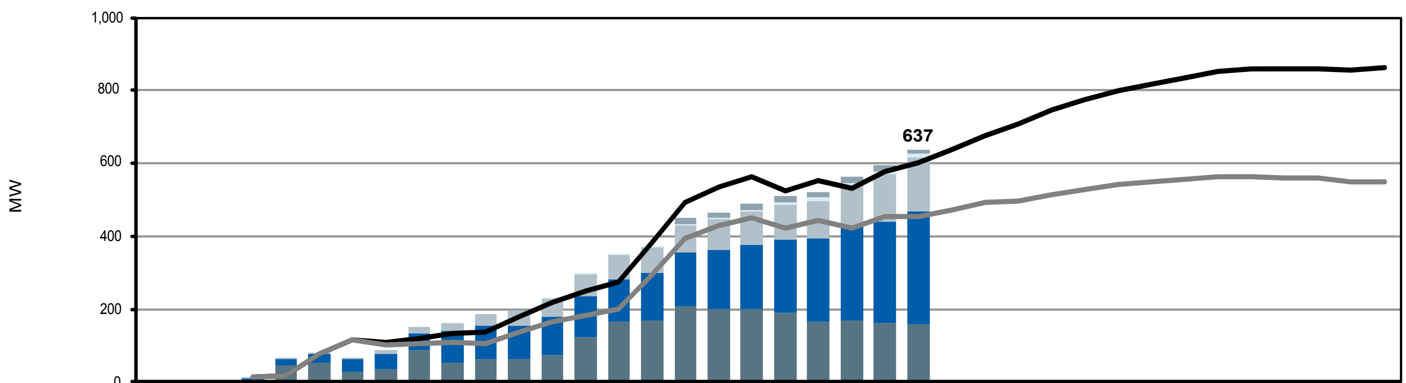


	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
DSM Support Programs													2	4	7	11
Codes & Standards	-	-	-	2	8	16	25	40	63	93	125	156	189	228	248	274
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incentive-Based - Efficiency	6	10	31	59	99	151	209	259	285	363	407	419	467	511	546	620
Plan	-			50	86	138	195	281	336	422	466	602	686	810	891	970
Plan (Incentive-Based Programs only)	-			50	86	138	195	252	279	327	350	435	491	544	603	634
Total Achieved	6	10	31	62	107	167	235	299	348	456	532	575	659	743	801	904

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	13	16	20	22	25	26	27	29														
Codes & Standards	298	323	352	382	430	481	553	628														
Incentive-Based - Customer Self Generation	11	132	93	103	88	95	77	91														
Incentive-Based - Efficiency	715	799	895	1,002	1,126	1,243	1,356	1,521														
Plan	1,088	1,199	1,350	1,569	1,753	1,736	1,906	2063	2214	2323	2489	2654	2787	2906	3003	3096	3184	3195	3191	3186	3157	3175
Plan (Incentive-Based Programs only)	713	782	879	1,157	1,310	1,293	1391	1,427	1,509	1,551	1,608	1,675	1,737	1,796	1,835	1,871	1,902	1,881	1,858	1,832	1,771	1,754
Total Achieved	1,037	1,270	1,359	1,509	1,669	1,846	2,014	2,269														

Note: Figures may not add due to rounding.

Exhibit E.5
Average Winter Demand Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation



	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
DSM Support Programs													1	1	2	3
Codes & Standards	-	-	-	1	2	4	6	10	15	23	32	40	49	59	64	70
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incentive-Based - Efficiency	0	1	4	10	17	26	34	42	46	86	91	93	105	113	119	131
Incentive-Based - Rate/Load	-	-	-	-	45	51	27	36	88	53	64	63	75	121	163	169
Plan				12	18	75	114	108	118	134	135	178	216	249	273	385
Plan (Incentive-Based Programs only)				12	18	75	114	101	104	110	105	136	166	183	200	296
Total	0	1	4	10	64	80	68	87	149	162	187	196	230	295	348	373

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	3	4	6	6	8	9	9	10														
Codes & Standards	76	82	89	97	105	113	131	150														
Incentive-Based - Customer Self Generation	16	16	16	16	16	16	16	10														
Incentive-Based - Efficiency	146	162	179	200	229	254	276	308														
Incentive-Based - Rate/Load	208	202	199	190	164	170	162	159														
Plan	491	535	564	524	551	531	578	603	638	674	707	746	773	798	816	835	852	858	858	859	856	861
Plan (Incentive-Based Programs only)	394	429	449	421	442	421	454	454	472	492	498	513	527	540	548	556	563	563	561	559	550	550
Total	450	466	488	509	521	562	594	637														

Note: Figures may not add due to rounding.

2012/13 Natural Gas Results

In 2012/13 alone, the Power Smart portfolio realized natural gas savings of 14.6 million cubic metres, 46% more than planned. The following tables provide a comparison between results and planned targets, where applicable.

Exhibit E.6

Annual Natural Gas Savings - Power Smart Portfolio

	2012/13 Actual	2012/13 Plan^	Total*
		millions of cubic metres	
PROGRAM & INITIATIVE			
Incentive-Based Programs	11.3	7.9	62.2
Codes & Standards	3.4	2.7	13.2
DSM Support Programs	0.6	0.5	20.3
	15.3	11.1	95.7
INTERACTIVE EFFECTS			
Incentive-Based Interactive Effects	(0.7)	(1.1)	(12.0)
NET IMPACT OVERALL	14.6	10.0	83.6

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

Exhibit E.7

2012/13 Power Smart Portfolio Natural Gas Costs

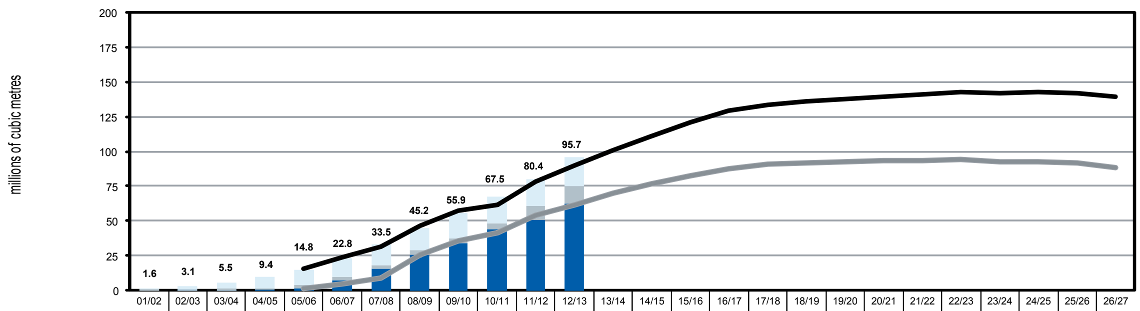
Power Smart Portfolio	2012/13
	millions of dollars
INCENTIVE-BASED PROGRAMS	8.4
SUPPORT COSTS, DSM SUPPORT PROGRAMS & STANDARDS	1.4
TOTAL NATURAL GAS PROGRAM COSTS	9.8

Note: Figures may not add due to rounding.

Total Natural Gas Results (2012/13 Results & Persisting Savings)

Cumulatively, the Power Smart portfolio has saved 83.6 million cubic metres of natural gas, 5% more than planned to the end of 2012/13. The cumulative savings to date represent 61% of the forecasted savings at benchmark year of 2026/27. To date, $79 million has been invested in Power Smart natural gas activities. The following graphs present cumulative natural gas savings achieved and corresponding targets.

Exhibit E.8
Natural Gas Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan



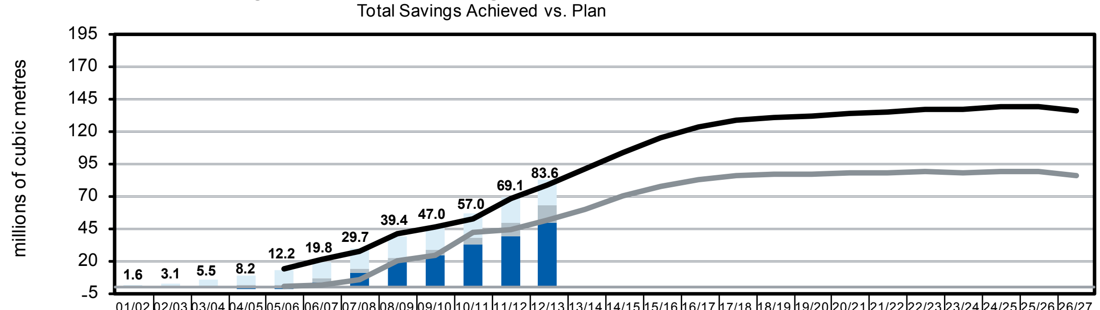
	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	1.2	2.4	4.3	7.7	11.3	13.2	15.3	16.4	18.3	19.0	19.7	20.3														
Codes & Standards	0.3	0.7	1.1	1.6	2.0	2.4	2.7	3.0	3.5	4.4	9.9	13.2														
Incentive-Based Efficiency	0.0	0.1	0.1	0.2	1.6	7.3	15.5	25.9	34.1	44.0	50.9	62.2														
Plan					15.4	23.9	31.2	46.4	57.3	61.2	78.0	89.8	101.2	111.4	120.8	129.3	133.6	135.9	137.6	139.5	141.0	142.6	142.2	142.5	142.2	139.6
Plan (incentived-based programs only)					1.5	4.3	9.0	25.7	35.6	41.7	54.1	61.7	69.9	76.8	82.8	87.9	91.0	92.0	92.6	93.3	93.8	94.3	92.9	92.5	91.6	88.5
Total Achieved	1.6	3.1	5.5	9.4	14.8	22.8	33.5	45.2	55.9	67.5	80.4	95.7														

Note: Figures may not add due to rounding.

Natural Gas Integrated Results

Some electric Power Smart programs have interactive effects which increase the consumption of natural gas. For example, a more energy efficient lighting system emits less heat and therefore results in more energy required for space heating. The integrated natural gas results are adjusted for interactive effects, and are represented in the following graph.

Exhibit E.9
Integrated Natural Gas Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan



	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	1.2	2.4	4.3	7.7	11.3	13.2	15.3	16.4	18.3	19.0	19.7	20.3														
Codes & Standards	0.3	0.7	1.1	1.6	2.0	2.4	2.7	3.0	3.5	4.4	9.9	13.2														
Incentive-Based Integrated	0.0	0.1	0.1	-1.0	-1.0	4.3	11.7	20.0	25.3	33.5	39.6	50.1														
Integrated Plan					14.8	21.5	27.9	41.4	46.3	52.8	68.6	79.6	91.8	105.1	116.1	124.6	128.8	131.0	132.7	134.5	136.0	137.6	138.0	139.8	140.2	137.5
Integrated Plan (Incentive-Based Programs only)					0.8	1.9	5.7	20.8	24.6	42.2	44.7	51.5	60.5	70.5	78.1	83.1	86.2	87.2	87.7	88.4	88.8	89.3	88.7	89.8	89.7	86.4
Total Achieved	1.6	3.1	5.5	8.2	12.2	19.8	29.7	39.4	47.0	57.0	69.1	83.6														

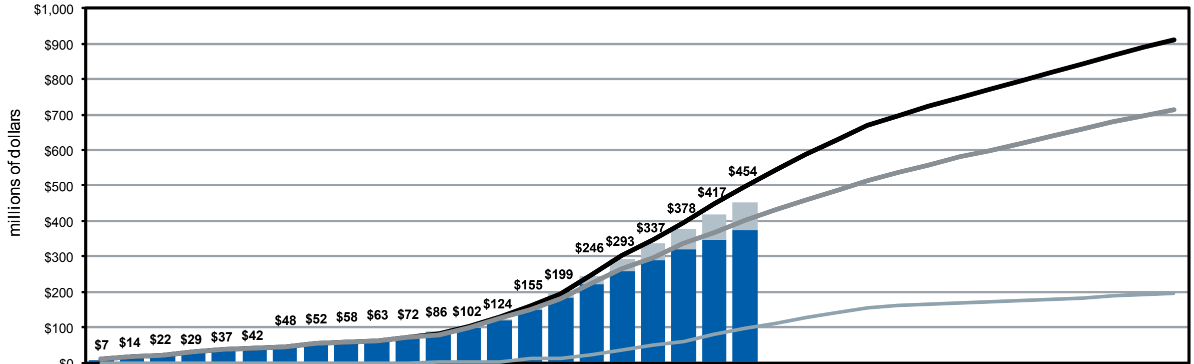
Note: Figures may not add due to rounding.
Targeted savings are unadjusted for programs not running or other revisions.

Power Smart Utility Costs

Total Power Smart expenditures in 2012/13 were $37 million, of which $27 million was spent on electric initiatives and $10 million was spent on natural gas initiatives. Cumulative Power Smart expenditures were $454 million, or 8% lower than the budgeted amount of $496 million. The positive spending variance can be credited to electric and natural gas efficiency spending, which were both below budget, 6% and 18% respectively.

Cumulative Power Smart expenditures of $454 million represent 50% of the overall cumulative 2026/27 budget, as reported in the IFF-12. The following graph depicts actual annual expenditures against planned.

Exhibit E.10
Utility Costs - Power Smart Portfolio
Cumulative Total Utility Cost vs. Plan
nominal dollars



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
Eval - Natural Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$2	$3	$6	$14	$24	$35	$47
Eval - Electricity	$7	$14	$22	$29	$37	$42	$48	$52	$58	$63	$71	$84	$100	$121	$149	$185	$222	$257	$290
Plan- Electricity & Natural Gas	$10	$16	$20	$32	$36	$41	$44	$54	$58	$63	$72	$81	$102	$130	$161	$195	$248	$302	$347
Plan- Electricity	$10	$16	$20	$32	$36	$41	$44	$54	$58	$63	$72	$80	$100	$128	$150	$182	$225	$265	$298
Plan - Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$2	$11	$13	$23	$37	$49
Total Eval	$7	$14	$22	$29	$37	$42	$48	$52	$58	$63	$72	$86	$102	$124	$155	$199	$246	$293	$337

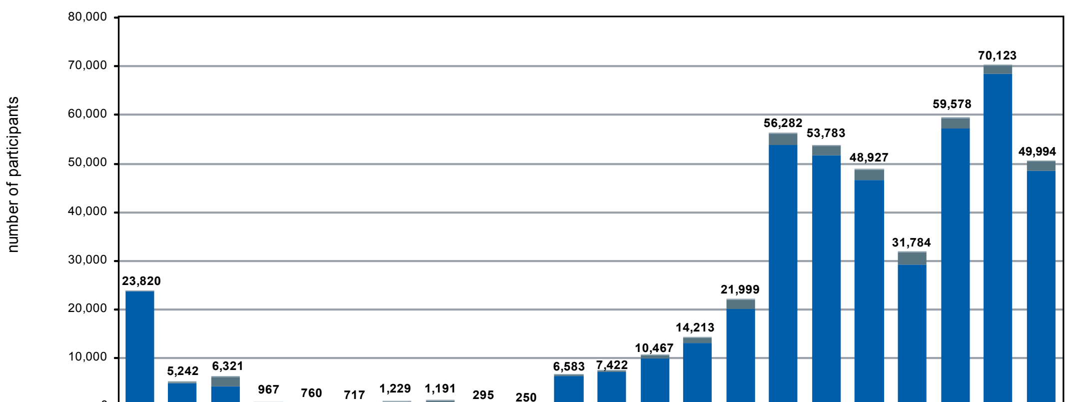
	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Eval - Natural Gas	$58	$69	$79														
Eval - Electricity	$319	$348	$375														
Plan- Electricity & Natural Gas	$396	$449	$496	$544	$587	$628	$668	$698	$725	$749	$773	$796	$819	$843	$866	$889	$910
Plan- Electricity	$335	$369	$400	$431	$459	$486	$513	$536	$559	$580	$600	$620	$639	$659	$679	$698	$715
Plan - Gas	$61	$80	$96	$112	$128	$142	$156	$161	$166	$169	$173	$176	$180	$184	$187	$191	$195
Total Eval	$378	$417	$454														

Note: Figures may not add due to rounding.

Customer Participation

The following graph illustrates that participation levels in Manitoba Hydro's Power Smart programs remain strong.

Exhibit E.11
Power Smart Program Participation



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Industrial	24	157	202	229	185	182	195	8	4	9	17	25	32	48	50	49	81	99	116	90	73	110
Commercial	65	273	1,959	738	575	334	325	502	291	241	305	364	538	1,020	1,849	2,364	2,041	2,136	2,491	2,256	1,526	1,895
Residential (excluding CFLs)	23,731	4,812	4,160	0	0	201	709	681	0	0	6,261	7,033	9,897	13,145	20,100	53,869	51,661	46,692	29,177	57,232	68,524	47,989
Total Achieved (excluding CFLs)	23,820	5,242	6,321	967	760	717	1,229	1,191	295	250	6,583	7,422	10,467	14,213	21,999	56,282	53,783	48,927	31,784	59,578	70,123	49,994

Note: Includes electric and natural gas participants of DSM support programs, cost recovery and incentive-based programs.
Participation for codes and standards is excluded.
Curtailable Rates Program participation is included in the industrial sector.
Customers may participate in more than one Power Smart program.
The 343,381 sales under the Residential Compact Fluorescent Lighting Program during 2004/05-2010/11 are excluded.
Figures may not add due to rounding.

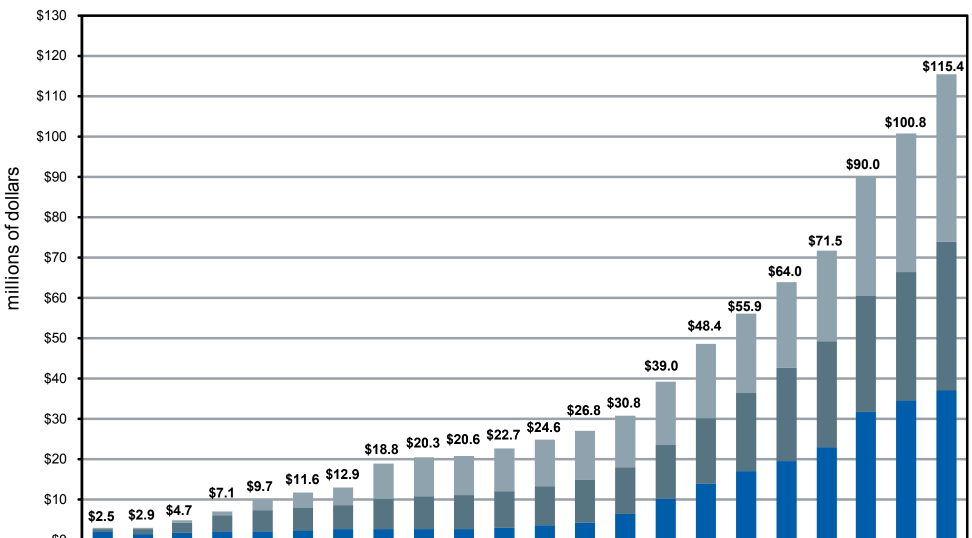
During 2012/13, there were nearly 50,000 participants in Power Smart DSM support programs and incentive-based programs. Excluding the Residential Compact Fluorescent Lighting Program, there have been approximately 472,000 participants cumulatively.

Participation of the Residential Compact Fluorescent Lighting Program has been excluded to provide a better indication of participation trends. The Residential Compact Fluorescent Lighting Program provided a low-cost option for achieving energy efficiency, and represents 44% of residential Power Smart participation and 42% of overall Power Smart participation.

Customer Bill Reductions

The annual bill reduction for participating customers due to annual and persisting results in 2012/13 of over $115 million is comprised of $88 million of savings on electric bills and $28 million on natural gas bills. Cumulatively, $801 million has been saved on electricity and natural gas bills.

Exhibit. E.12
Combined Electricity & Natural Gas Customer Bill Reduction (2012$)
Annual Reductions to Date by Sector
millions of dollars



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02
Industrial	$0.0	$0.3	$0.4	$1.1	$2.5	$3.7	$4.2	$8.8	$9.5	$9.5	$10.6
Commercial	$0.5	$1.2	$2.6	$4.0	$5.1	$5.6	$6.1	$7.5	$8.3	$8.6	$9.1
Residential	$2.0	$1.4	$1.7	$2.0	$2.1	$2.4	$2.6	$2.5	$2.5	$2.5	$3.0
Total	$2.5	$2.9	$4.7	$7.1	$9.7	$11.6	$12.9	$18.8	$20.3	$20.6	$22.7

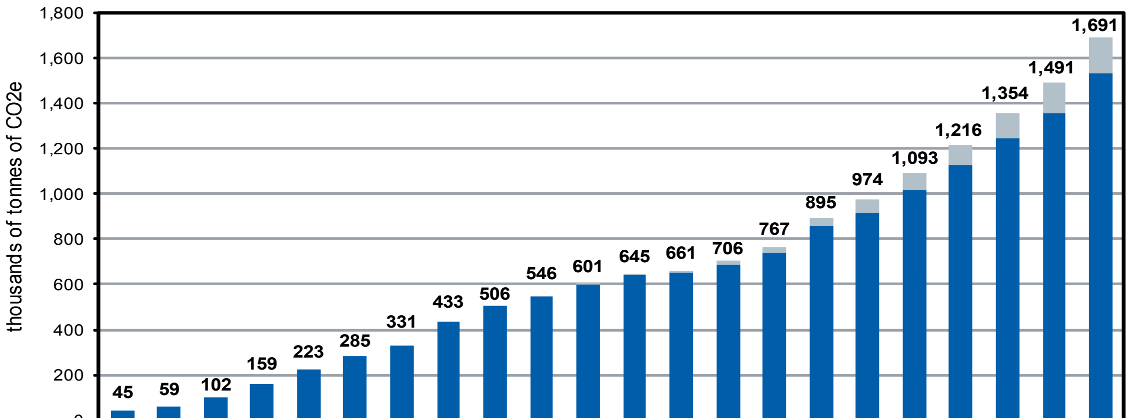
	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Industrial	$11.5	$11.9	$12.9	$15.4	$18.4	$19.6	$21.4	$22.3	$29.6	$34.4	$41.5
Commercial	$9.6	$10.6	$11.6	$13.4	$16.2	$19.4	$23.0	$26.2	$28.7	$32.0	$36.9
Residential	$3.5	$4.3	$6.2	$10.2	$13.8	$16.9	$19.5	$23.0	$31.7	$34.4	$36.9
Total	$24.6	$26.8	$30.8	$39.0	$48.4	$55.9	$64.0	$71.5	$90.0	$100.8	$115.4

Note: Includes electric and natural gas participants.
Bill reductions exclude savings due to codes & standards.
Demand savings resulting from the Curtailable Rates Program are excluded from this analysis.
Natural gas bill reduction includes primary and distribution rates only.
Figures may not add due to rounding.

Greenhouse Gas Reductions

The 2,269 GW.h savings from electric Power Smart programs and 84 million cubic metres of savings from natural gas Power Smart programs equate to a greenhouse gas emission reduction of approximately 1,691 thousand tonnes of carbon dioxide equivalent emissions. This is comparable to removing nearly 338 thousand vehicles from the road for one full year. The majority (91%) of the greenhouse gas emission reductions result from electric Power Smart program activity through indirect emission reductions from Manitoba Hydro export sales displacing coal and natural gas fuelled generation outside of Manitoba. The remaining (9%) emission reductions are direct reductions that occur as a result of lower natural gas consumption in Manitoba.

Exhibit E.13
Total Annual Greenhouse Gas Emission Reductions
Due to Electric & Natural Gas Savings
thousands of tonnes of CO_2e



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Natural Gas											3	6	10	16	23	38	56	75	89	108	131	159
Electric	45	59	102	159	223	285	331	433	506	546	598	639	650	691	743	857	917	1,018	1,127	1,246	1,359	1,532
Total	45	59	102	159	223	285	331	433	506	546	601	645	661	706	767	895	974	1,093	1,216	1,354	1,491	1,691

Note: Figures may not add due to rounding.

The Affordable Energy Fund

The Affordable Energy Fund was established in 2006/07 through the Winter Heating Cost Control Act. The purpose of the fund is to provide support for programs and services that achieve specific objectives. The objectives include encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, lower income customers and seniors, and encouraging the use of alternative energy sources such as renewable energy.

Exhibit E.14 outlines the Affordable Energy Fund expenditures in 2012/13 and cumulatively.

Exhibit E.14

Summary of Affordable Energy Fund Expenditures

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative
				thousands of nominal dollars				
Affordable Energy Program	256	219	893	1,672	2,666	3,131	3,332	12,168
Geothermal Support								
Waverley West Demonstration Project*	619	252	5	0	-1	-1	-1	873
Earth Power Loan Subsidy	0	19	69	105	108	108	91	500
Province of Manitoba Cooperative Advertising	0	0	18	0	0	0	0	18
Geothermal Support Total	619	270	92	104	108	107	91	1,391
Community Support & Outreach	0	0	35	130	133	139	114	551
Oil & Propane Heated Homes	0	75	85	31	32	24	0	246
Special Projects								
Res. Energy Assessment Services (ecoENERGY Audits)	0	61	241	85	119	39	0	545
Oil & Propane Furnace Replacement	0	0	6	36	42	17	10	112
Res. Solar Water Heating Program	0	0	89	119	56	11	10	285
Power Smart Residential Loan	0	0	0	130	312	354	510	1,306
Oil & Propane Heated Homes - Additional Funding	0	0	0	0	0	10	26	37
Special Projects Total	0	61	336	371	529	431	556	2,284
Community Energy Development								
ecoENERGY Program Funding - Additional Funding	0	0	0	0	0	2,817	1,241	4,058
Community Energy Development Total	0	0	0	0	0	2,817	1,241	4,058
DSM INITIATIVES SUBTOTAL	875	625	1,441	2,308	3,468	6,649	5,334	20,700
Manitoba Electric Bus	0	0	0	0	0	700	75	775
Energy & Resource Fund	0	0	0	750	0	0	0	750
Fort Whyte EcoVillage	0	0	0	0	0	120	0	120
Diesel Community Green Pilot Demonstration	0	0	0	0	0	3	-3	0
TOTAL EXPENDITURES	875	625	1,441	3,058	3,468	7,472	5,406	22,345

* Negative costs represent loop lease payments from customer to Manitoba Hydro.
** Reversal of an incorrect charge that took place in 2011/12 is indicated by the negative cost.

Furnace Replacement Budget

The Furnace Replacement Budget was established in 2007/08 as a result of Public Utilities Board Order 99/07. The purpose of the budget is to establish and administer a Furnace Replacement Program for lower income customers. In 2012/13 alone, customers installed 630 furnaces and 9 boilers through the Furnace Replacement Program. Cumulatively to the end of 2012/13, 2,525 furnaces and 57 boilers have been installed to the end of 2012/13 as a result of the program. Exhibit E.15 outlines Lower Income natural gas furnace replacement expenditures to date.

Exhibit E.15

Summary of Furnace Replacement Expenditures

	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative
			thousands of nominal dollars			
Natural Gas Furnace Replacement	264	815	1,312	1,627	2,167	6,185
TOTAL EXPENDITURES	264	815	1,312	1,627	2,167	6,185

Table of Contents

1.0 Introduction

1.1 Background

In 1989, Manitoba Hydro launched the first of many Demand Side Management (DSM) programs, the Outdoor Timer Program. Soon after in 1991, Manitoba Hydro established Power Smart, the customer-oriented brand for all of Manitoba Hydro's DSM programs, initiatives and activities. DSM resource options are assessed and included in Manitoba Hydro's Integrated Resource Planning process. These resource options are developed to provide alternatives to traditional sources of power generation. Power Smart initiatives are justified based on their relative cost compared to traditional generation resource options and the customer service value realized by customers.

Since purchasing Centra Gas in 1999, Manitoba Hydro has integrated natural gas conservation into the Corporation's overall Power Smart initiative. This report provides an integrated approach to evaluating the results. Net energy savings reported are due to the combined electricity and natural gas energy conservation efforts. In this regard, any increased natural gas consumption resulting from electricity efficiency efforts (due to interactive effects) are captured and netted against natural gas conservation efforts. Interactive effects were not accounted for prior to the 2002/03 reporting period.

Energy conservation initiatives are designed to reduce customer energy requirements through energy efficient measures (i.e. using less energy to obtain comparable or superior services). Rate/Load management activities are put in place to reduce energy demands through programs offered to alter the timing of customer demand (i.e. Curtailable Rates Program). Customer self-generation programs are created to encourage customer on-site generation.

Manitoba Hydro's Power Smart strategy focuses on creating a sustainable market change where energy efficient technologies and practices become the market standard (market transformation). The approach used to create and maintain market transformation varies by product and market segment, and generally involves a combination of the following activities:

- DSM Support Programs & cost recovery programs;
- Incentive-based promotional programs, including:
    - Efficiency programs,
    - Customer self-generation programs and
    - Rate/Load management programs.
- Efforts to encourage and support implementation of energy efficiency into codes and standards.

The work in each of these different areas supports the overall Power Smart objective as well as other corporate goals, including: providing customers with exceptional value, protecting the environment and capturing additional electricity export sales.

The Power Smart DSM initiative is designed to encourage the efficient use of energy in the residential, commercial, agricultural, institutional and industrial customer sectors. More than thirty-five incentive-based programs and many other DSM support programs have been offered over the last twenty-four years, with impact evaluations of all incentive-based programs prepared annually.

By evaluating the incentive-based programs, Manitoba Hydro can determine its overall progress in achieving its corporate objectives, and can adjust individual program targets and strategies to reflect market reaction and market changes.

1.2 Power Smart Strategy

Manitoba Hydro's Power Smart strategy is to create a sustainable market change where energy efficient technologies and practices become the market standard (market transformation). To be effective in achieving the desired outcome, the corporation's strategy involves working along multiple tracks, including:

- Providing customers with information and services related to energy efficiency;
- Offering incentive-based Power Smart programs designed to create market awareness, knowledge and acceptance of energy efficient technologies and products;
- Making available cost recovery financing to help customers overcome the financial barriers to the adoption of energy efficient technologies;
- Working with industry and trade allies to gain support for the Corporation's Power Smart efforts;
- Working with other utilities and government agencies in joint efforts to incorporate energy efficiency in codes, standards and regulations;
- Undertaking communication and marketing efforts focused on promoting Power Smart programs and the Power Smart brand name;
- Leveraging the Power Smart brand through activities such as establishing "Power Smart Design Standards", and
- Making a sustainable and long-term commitment to the efficient use of energy.

1.3 Power Smart Brand & Perception

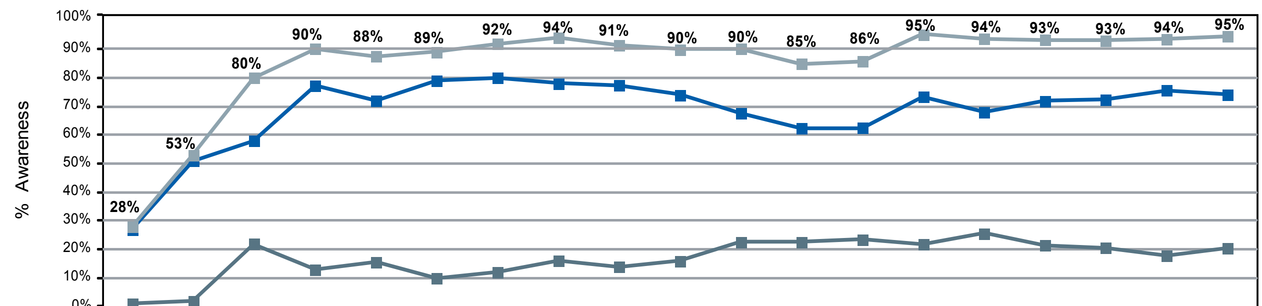
Power Smart is the brand name used by Manitoba Hydro since 1991 to promote its energy efficiency programs and services.

Manitoba Hydro continues to successfully maintain the Power Smart brand's profile with 95% of respondents currently indicating they recognize the brand name. This includes 21% of respondents who independently recall (unaided recall) the Power Smart brand name, and 72% of respondents who say they recognize the brand name when the Power Smart brand name is identified (aided recall).

The Power Smart campaign, being distinct from the marketing/promotional activities associated with specific Power Smart DSM programs, is a mass communications campaign undertaken to improve public awareness of the Power Smart brand and its association with energy efficiency, low electricity rates and environmental conservation.

Approximately one-third (32%) of respondents said they had participated in a Manitoba Hydro Power Smart program.

Exhibit 1.3
Power Smart Brand Awareness



	90/91	91/92	92/93	95/96	96/97	98/99	99/00	00/01	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Unaided Awareness	1%	2%	22%	13%	16%	10%	12%	16%	14%	16%	23%	23%	23%	22%	26%	22%	21%	18%	20%
Aided Awareness	27%	51%	58%	77%	72%	79%	80%	78%	78%	74%	68%	62%	63%	73%	68%	72%	72%	76%	74%
Total Awareness	28%	53%	80%	90%	88%	89%	92%	94%	91%	90%	90%	85%	86%	95%	94%	93%	93%	94%	95%

Note: Power Smart awareness was not measured in 93/94, 94/95, 97/98 or 01/02.
Figures may not add due to rounding.

Customers continue to strongly agree that the Power Smart brand and programs 'Encourage Customers to be more Energy Efficient' (83% answered 7 or higher on a 1-10 agreement scale), 'Help Customers Save Money on their Energy Bills' (75%), and 'Help Conserve the Environment' (75%). Respondents continue to report more moderate levels of agreement that the Power Smart brand and programs 'Ensure there will be Electricity Available for Manitobans in the Future' (67%) and 'Contribute to Manitobans paying among the Lowest Prices for electricity in Northern America' (56%).

The vast majority of customers report they are very satisfied with Manitoba Hydro's 'Efforts to Encourage Customers to be More Energy Efficient' with 82% reporting a satisfaction level of 7 or higher on a 1-10 satisfaction scale.

1.4 Purpose of Report

Power Smart is an important component of Manitoba Hydro's Integrated Power Resource Plan.

Manitoba Hydro's Power Smart DSM targets for electric energy and average winter demand savings at generation are 3,175 GW.h and 861 MW by 2026/27, as outlined under the 2012 Base DSM Forecast. These targets represent the expected impact of efficiency codes and standards, DSM support programs and incentive-based program activities. Manitoba Hydro's Power Smart program activity is expected to contribute the greatest portion of the savings, with projected energy and demand savings of 1,754 GW.h and 550 MW by 2026/27.

Manitoba Hydro's Power Smart DSM target for natural gas savings is 138 million cubic metres by 2026/27, as outlined in the 2012 Base DSM Forecast. This target represents the expected impact of incentive-based efficiency program activities, DSM support programs, interactive effects from electricity programs, as well as savings resulting from efficiency codes and standards. Manitoba Hydro's Power Smart program activity is expected to contribute the greatest portion of the savings, with projected savings of 86 million cubic metres by 2026/27.

While this report highlights all activities and results from the overall Power Smart portfolio, the emphasis will be on incentive-based programs. Annual results for 2012/13 will be measured against the planned savings specified in the 2012 Base DSM Forecast.

More specifically, this report will:

- Report the energy and demand savings achieved by incentive-based Power Smart programs;
- Report the utility costs associated with all Power Smart programs and initiatives;
- Report the cost-effectiveness of incentive-based Power Smart programs.

Refer to APPENDIX A - 'Sources of Evaluation and Planning Estimates' for details of the information considered when preparing program plan estimates and program evaluation results. Refer to APPENDIX B - 'Explanation of Benefit-Cost Ratios used in DSM Economic Metrics' for formulas used to assess cost-effectiveness.

2.0 Power Smart Portfolio Review

Manitoba Hydro's Power Smart efforts include DSM support programs, cost recovery programs, energy efficient codes and standards and incentive-based Power Smart programs. The following section includes a synopsis of the current Power Smart initiatives.

2.1 Power Smart DSM Support Programs & Cost Recovery Programs

One of the primary drivers in Manitoba Hydro's Power Smart activities is providing value-added customer service. This is achieved by offering customers information and advice, financing services, access to energy efficiency information and providing energy efficient solutions. Through these efforts, Manitoba residents and businesses are provided a number of benefits including:

- Enabling customers to improve the comfort and productivity of their work and home environments while reducing their energy bills;
- Lower electricity rates;
- Assisting businesses in becoming more competitive in national and international markets; and
- Creating employment opportunities within Manitoba for manufacturers, distributors, retailers, trade allies and installers of energy efficient products and services.

2.1.1 Launch Date of DSM Support Programs & Cost Recovery Programs

Exhibit 2.1.1-A identifies the launch dates of all current and discontinued DSM support programs and cost recovery programs.

Exhibit 2.1.1-A

Launch Date of DSM Support Programs & Cost Recovery Programs

INITIATIVE	LAUNCH DATE
RESIDENTIAL	
Power Smart Residential Loan	February, 2001
ecoENERGY Program^	March, 2001
Residential Earth Power Program	April, 2002
Power Smart Residential PAYS Program	November, 2012
COMMERCIAL	
Power Smart Recreation Facility Survey	May, 1998
Religious Buildings Initiative	May, 2001
DISCONTINUED/COMPLETED PROGRAMS	
Wisdom in Saving Energy (W.I.S.E.) Home Program	June, 2001
Power Smart Energy Manager - Pilot	September, 2001
Energy Saver Presentations^^	January, 2002
New Home Program Workshop	January, 2002
R-2000 Home Program component of the New Home Program*	February, 2002
Power Smart Design Standards**	September, 2002
Solar Hot Water Heating	November, 2008

^ Formerly called EnerGuide.
^^ Formerly called Home Energy Saver Workshops.
* In 2004/05, the R-2000 Home Program was grouped under the New Home Program.
** Power Smart Design Standards is now a component of the commercial incentive-based New Buildings Program.

Exhibit 2.1.1-B provides an overview of the annual and total number of participants for DSM support programs and cost recovery programs.

Refer to APPENDIX C - 'Total Power Smart Participation' for a detailed list of historical participation.

Exhibit 2.1.1-B

DSM Support Programs & Cost Recovery Program Participation

INITIATIVE	2012/13	Cumulative
	Number of Participants	
RESIDENTIAL		
Financing Programs		
Power Smart Residential Loan*	6,202	70,358
Power Smart Residential PAYS Program	52	52
Residential Earth Power Program		
Geothermal Loan	24	1,210
Solar Hot Water Heating	0	14
	6,278	71,634
Mail In/On-Line Energy Assessments	286	4,297
ecoENERGY Program^	1,186	54,272
	7,750	130,203
COMMERCIAL		
Religious Buildings Initiative	0	231
Power Smart Recreation Facility Survey	0	69
	0	300
DISCONTINUED/COMPLETED PROGRAMS		
Wisdom in Saving Energy (W.I.S.E.) Home Program	n/a	5,391
Energy Saver Presentations^^	n/a	3,956
New Home Program Workshop	n/a	854
Earth Power Consumer Workshops**	n/a	688
R-2000 Home Program component of the New Home Program ^^^	n/a	63
Power Smart Energy Manager - Pilot	n/a	38
Solar Hot Water Heating	n/a	36
	n/a	11,026
TOTAL	7,750	141,529

* Participation includes completed projects.
** Includes residential and commercial participants.
^ Formerly called EnerGuide. Participation includes 'D' & 'E' audits.
As Manitoba Hydro highly subsidized the evaluation cost of Amerispec and EnerGuy participants, they are included in the participation figures for 2011/12 and 2012/13.
^^ Formerly called Home Energy Saver Workshops.
^^^ In 2004/05, the R-2000 Home Program was grouped under the New Home Program.
Note: This table includes electric and natural gas Power Smart participants.
Customers may participate in more than one Power Smart program.
Participation is measured by completed projects, and excludes free drivers and market transformation.

2.1.2 DSM Support Programs & Cost Recovery Program Activity

DSM support programs and cost recovery programs provide numerous benefits to Manitobans. Depending on the nature of the program, savings resulting from specific programs will be quantified to the extent that these savings can be reasonably determined. Estimated savings are generally calculated using engineering estimates, as well as sales and market data provided by program coordinators. Regular assessments include a qualitative evaluation of the benefits, with service levels adjusted accordingly. The following outlines the Power Smart DSM support programs and cost recovery programs that were running in 2012/13.

Power Smart Residential Assistance

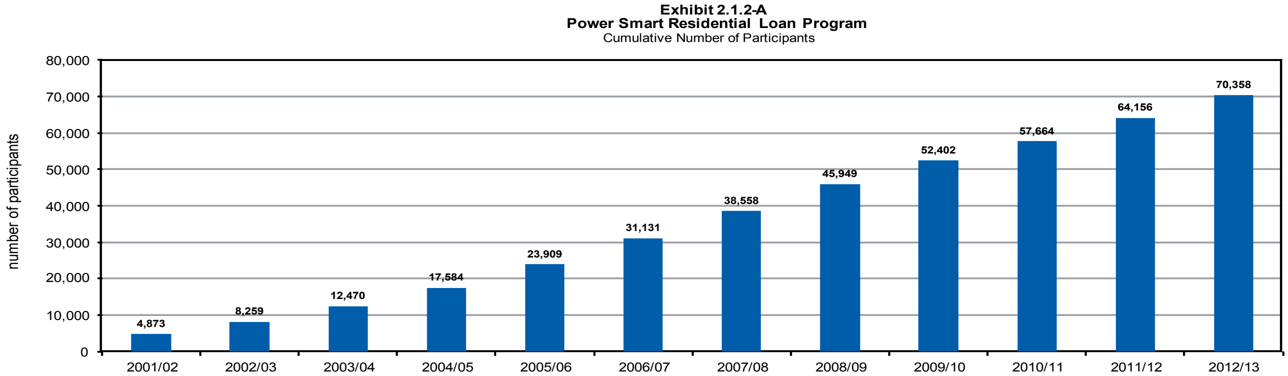
A number of tools are offered to residential customers to encourage and assist homeowners to make energy efficient renovations and energy use decisions that increase comfort and reduce home energy bills. The following services are offered under this initiative:

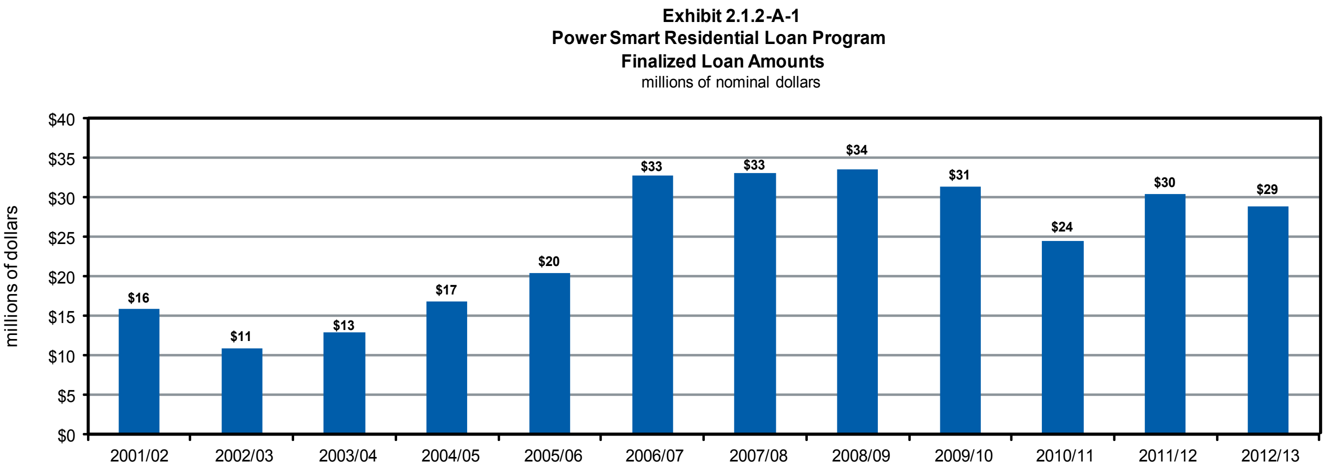
- Customers can complete a mail-in or online survey to evaluate the energy use in their home. Regardless of the method of participation, the customer receives a customized report that includes easy-to-read graphs summarizing overall energy usage, a breakdown of the house characteristics that contribute to heating costs, a list of recommended upgrades and a Power Smart target comparing the current energy consumption of their home to a home upgraded with the recommended Power Smart measures;
- Detailed brochures and renovation booklets providing information for selecting and installing Power Smart measures and tips for achieving low cost or no-cost energy savings in the home;
- Customers can email a Power Smart Energy Expert with energy conservation-related questions; and
- Convenient on-bill financing to complete energy efficient renovations as outlined below.

Power Smart Residential Loan

The Power Smart Residential Loan Program offers convenient on-bill financing to encourage homeowners to complete energy efficient renovations to increase comfort and reduce home heating bills.

Since its inception, the Power Smart Residential Loan Program has had more than 70,000 participants, borrowing more than $292 million in total. To date, $64 million in loans remain outstanding. Exhibit 2.1.2-A displays participation under the Power Smart Loan Program, and Exhibit 2.1.2-A-1 summarizes finalized loan amounts. Effective November 5, 2012, the interest rate was increased to 4.8% (from 3.9%).





Power Smart Residential PAYS Program

In June 2012, the Province of Manitoba passed Bill 24 - The Energy Savings Act. In response, Manitoba Hydro launched the Power Smart Residential PAYS Program on November 5, 2012.

The Power Smart Residential PAYS Program offers extended financing terms for energy efficient upgrades. Customers can use their estimated annual utility bill savings, from installing a particular efficient measure, to pay for that measure (or part thereof). Customers have the option to transfer the monthly payment to the next homeowner or tenant, who will also benefit from the upgrade.

In its first year, the Power Smart Residential PAYS Program had 52 participants, borrowing approximately $225,000.

Residential Earth Power Program

Manitoba continues to be a leader in the geothermal industry with close to 9,000 residential installations to date.

The Residential Earth Power Program's primary objective is to maximize the adoption of geothermal heat pump technology in order to offset the use of conventional electric heating systems.

To facilitate this objective, the Residential Earth Power Program has developed a comprehensive strategy to assist efforts of local stakeholders in developing a sustainable provincial geothermal industry. Since its launch in 2002, the program has focused efforts in mitigating three key market barriers which include:

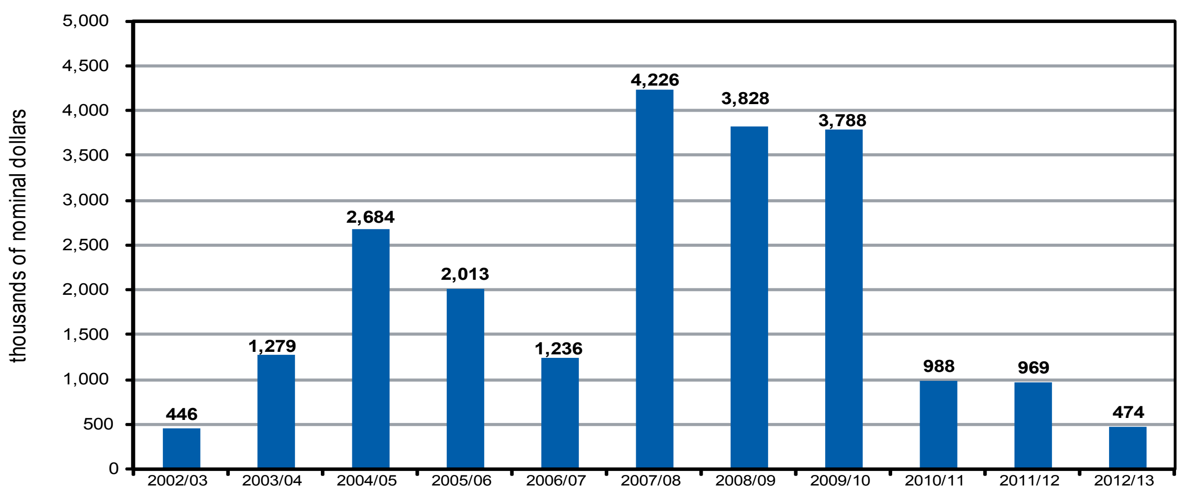
- Consumer awareness;
- Underdeveloped industry infrastructure; and
- High capital cost.

In 2002, the Residential Earth Power Program introduced convenient financing through the Residential Earth Power Loan, a vital component of the program.

The original terms of the loan offered financing up to $15,000 over a term up to fifteen years at a fixed interest rate of 6.5%. In April 2007, changes were made to the loan terms which increased the amount of financing available to $20,000 and lowered the interest rate to 4.9% for the first five years of a customer's loan. The interest rate on the balance of the loan term will be set up at prevailing interest rates. The lower initial term interest rate is subsidized by the Affordable Energy Fund.

Manitoba Hydro's Residential Earth Power Loan has continued to be an effective tool in facilitating residential geothermal installations. In 2012/13, a total of 22 customers financed their geothermal systems through the Residential Earth Power Loan. This brings the total number of geothermal loan participants to 1,208 since its inception in 2002/03, equivalent to $19.3 million in financing. As well, residential geothermal market activity has been strong due to the Provincial Green Energy Tax Credit and the $4,375 federal ecoENERGY grant. Since November 2008, the Residential Earth Power Loan has also offered financing for residential solar water heating systems. For a maximum term of 15 years at 4.0%, up to $7,500 can be borrowed. A total of 14 solar installations, equivalent to $92,700 thousand have been financed to date.

Exhibit 2.1.2-B
Residential Earth Power Loan
Annual Loan Amounts
thousands of nominal dollars



Residential geothermal installations in Manitoba have continued to decrease over the past three years. The recession experienced in 2009 has led to lower disposable income and increased customer reluctance to take on more debt. All of which have had a dramatic effect on geothermal installations throughout Canada. Other factors contributing to the decrease include falling natural gas prices due to increased supply through the emergence of shale gas exploration.

ecoENERGY Program (Formerly EnerGuide)

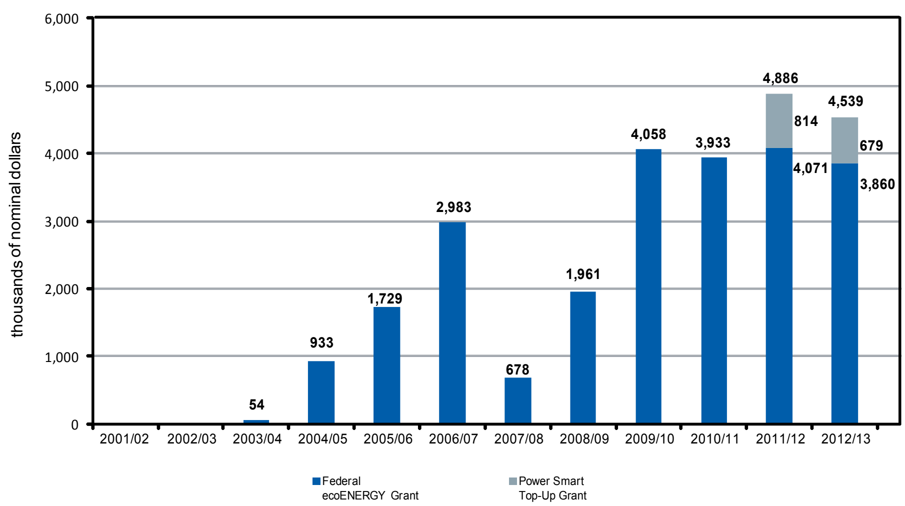
In July 2011, the Federal Government announced the re-instatement of the ecoENERGY Retrofit Grants Program. The reinstated program would run from June 6th, 2011 to March 31st, 2012. To qualify for a grant, homeowners were required to have a pre-retrofit energy evaluation on their home, implement the energy efficient upgrades and have a post-retrofit energy evaluation completed within this time frame. Manitoba Hydro immediately began offering the pre-retrofit energy evaluations required for homeowners to qualify for federal grants, at a subsidized price of $180. Funding for all subsidies was secured from the Affordable Energy Fund.

The grants were based on qualifying energy saving improvements, with a maximum total grant amount of $5,000 per residence (grants subject to availability).

On October 21st, 2011, The Province of Manitoba and Manitoba Hydro announced three initiatives to further encourage program participation:

- A reduction in price of the pre-retrofit evaluation to $45.
- A new Power Smart grant for ecoENERGY participants who qualified for federal grants, consisting of a top-up equating to 20% of the federal grant, in addition to the Home Insulation Program rebate.
- A reduction in the Power Smart Residential Loan interest rate from 4.9% to 3.9%.

Exhibit 2.1.2-C
ecoENERGY Program Grants Paid to Manitoba Hydro Customers
(thousands of nominal dollars)



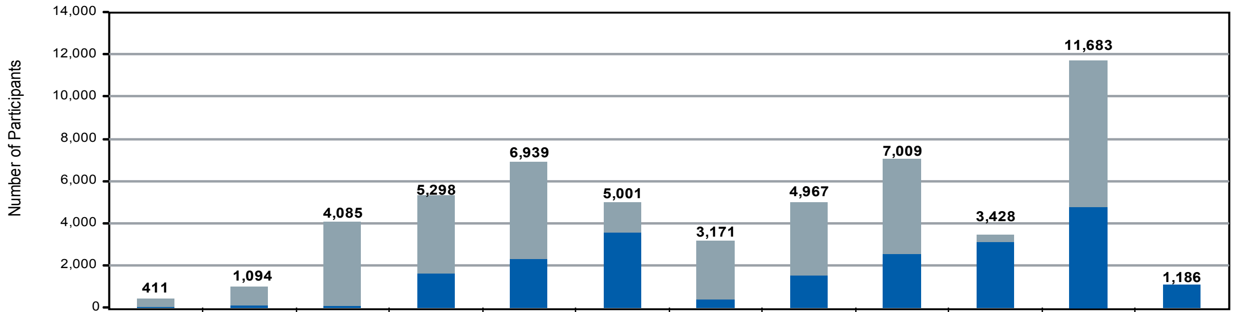
Note: Activity prior to 2007/08 was under the former EnerGuide Program.
As Manitoba Hydro highly subsidized the evaluation cost of Amerispec and EnerGuy participants, they are included in the participation figures for 2011/12 and 2012/13.

As seen above, federal grants paid to Manitobans more than doubled between 2008/09 and 2009/10. Since then, this amount has remained quite constant, peaking at over $4 million in 2011/2012 with the relaunch of the program.

In 2012/13, the average federal grant paid in Manitoba was $2,294 and the average Power Smart grant was $403. The most popular upgrades were furnaces, air sealing and attic insulation.

Additional support from Manitoba Hydro for the ecoENERGY program (the evaluation price reduction and Power Smart grant) were retroactive to June 6th, 2011 and applicable to all Manitoba service organizations. Funding for all three initiatives was allocated from the Affordable Energy Fund.

Exhibit 2.1.2-C-1
ecoENERGY Program
Number of D & E Participants



	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/2013
D Assessments	410	1,015	3,994	3,689	4,656	1,447	2,775	3,468	4,502	347	6,926	0
E Assessments	1	79	91	1,609	2,283	3,554	396	1,499	2,507	3,081	4,757	1,186
Total Assessments	411	1,094	4,085	5,298	6,939	5,001	3,171	4,967	7,009	3,428	11,683	1,186

Note: Activity prior to 2007/08 was under the former EnerGuide Program.
As Manitoba Hydro highly subsidized the evaluation cost of Amerispec and EnerGuy participants, they are included in the participation figures for 2011/12 and 2012/13.

In January 2012, the Federal Government closed the program to new participants, but maintained the March 31st, 2012 retrofit completion deadline for customers who had already booked their pre-retrofit evaluation. Due to the short duration of the re-instated program, the Federal Government succumbed to pressure received from all provinces nationwide, and allowed post-retrofit evaluations to be completed up until June 30th, 2012, with program paid top-up grants continuing until November 24, 2012. This relieved the pressure that was being experienced by the evaluator industry and allowed for more retrofits to be completed.

Power Smart Recreation Facilities Survey

The Power Smart Recreation Facilities Survey was created to help ice arenas and curling rinks reduce their operating costs by providing operators with an understanding of the energy use and potential energy saving measures within the facility. Technical staff at Manitoba Hydro review comprehensive surveys completed by facility operators and an evaluation report is prepared. The report compares the energy use of the facility with similar facilities in Manitoba and provides a list of possible energy saving opportunities. In October 2002, a guide called *Saving Money Through Energy Efficiency - Guidelines for Operators of Manitoba's Rinks and Arenas* was developed to assist rink operators to operate their facilities more efficiently, and to present practical ideas for saving money by reducing energy use. This guide has been updated and is now called *Energy Efficiency Guide for Ice Arenas and Curling Rinks*.

Religious Buildings Initiative

The Religious Buildings Initiative was designed to assist religious organizations in finding ways to make their buildings more energy efficient. The initiative offers a benchmark audit and a loan of 5.5% to assist religious facilities in carrying out efficiency improvements. The benchmark audit report outlines how energy is being used in the building and indicates potential energy saving measures. As part of the Religious Buildings Initiative, a guide called *Energy Efficiency Guide for Religious Buildings* was created. This energy and water efficiency guide assists people involved in the operation and maintenance of religious buildings to develop an action plan and take steps toward improving the efficiency of their buildings.

2.2 Energy Codes, Performance Standards & Energy Efficiency Regulations

Energy codes and performance standards are needed at every stage of market transformation, starting with initial evaluations of energy efficiency improvement opportunities, through to the design and implementation of incentive-based and non-incentive-based conservation programs intended to accelerate the adoption of energy efficient measures. And finally, as core ingredients for efficiency regulations aimed at removing laggard technologies from the market.

Performance standards provide the fundamental basis on which to measure, report and compare energy performance. As such, they form a core building block for evaluating the performance of energy efficient measures and comparing performance between competing products and technologies. Energy codes establish the criteria for understanding, quantifying and managing the energy performance of buildings and energy-consuming equipment operating within them. Performance standards are generally a key ingredient of energy codes, providing the basis on which to measure energy performance. While energy codes establish the metrics for evaluating building design and performance. Together, these two mechanisms are used to develop programs that support the optimal or minimum use of energy in the marketplace, limited only by technical potential and economic constraints.

Energy efficiency regulations are typically implemented towards the end of the market transformation process as energy efficient technologies mature and become generally accepted within the industry. Regulations are designed to remove technologies from the market that lag behind an established performance baseline agreed to by industry and government regulators. While the level of efficiency achieved through energy efficiency regulations is typically less than the optimal or minimum level of energy consumption achieved through directed incentive-based and non-incentive-based programming, regulation continues to be an effective and permanent method for removing products from the market with lower than desired energy performance.

Manitoba Hydro has adopted a proactive strategy that supports the development and acceptance of industry-wide performance standards and energy codes, through active participation in standards organizations such as the Canadian Standards Association Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER) and work with energy code steering committees at both federal and provincial levels. In many instances, Manitoba Hydro representatives are leaders within these working groups, driving forward development and acceptance of new performance standards and energy codes. Further to this, Manitoba Hydro adopts the use of these standards and codes in the design and implementation of its conservation programs, enhancing the overall effectiveness and market acceptance of these efforts. Finally, Manitoba Hydro works closely with federal, provincial and municipal regulators to identify and remove technologies from the market that lag behind accepted performance thresholds, providing support for the development and adoption of energy efficiency regulations. These efforts prevent products and measures with poor energy performance from gaining a foothold in the market and compromising efforts to transform markets to a more energy efficient state.

2.3 Power Smart Incentive-Based Programs

Power Smart incentive-based programs are designed in consideration of specific market parameters and characteristics impacting market acceptance of the targeted energy efficient technology or product. Examples of such factors are industry/customer awareness and appetite for acceptance, availability of competing products, state of product life cycles, cost barriers, training barriers, state of existing codes and standards, etc.

2.3.1 Launch Date & Participation of Incentive-Based Power Smart Programs

Exhibit 2.3.1-A identifies the launch dates of current and past Power Smart incentive-based programs.

Exhibit 2.3.1-B provides an overview of the annual and total participation of each incentive-based program.

Refer to APPENDIX C - 'Total Power Smart Participation' for a detailed summary of historical participation.

For a description of current incentive-based Power Smart programs, see list in Section 2.3.2. APPENDIX D provides a synopsis of discontinued Power Smart programs.

Exhibit 2.3.1-A

Launch Date of Incentive-Based Programs

PROGRAM	YEAR LAUNCHED
RESIDENTIAL	
Home Insulation	May, 2004
Affordable Energy Program	December, 2007
Affordable Energy Fund - Propane & Oil Furnace/Boiler	May, 2009
Water & Energy Saver	September, 2010
Refrigerator Retirement	June, 2011
COMMERCIAL	
Commercial Lighting	April, 1992
Internal Retrofit	July, 1995
Commercial Custom Measures	December, 1995
Commercial Building Envelope	December, 1995
Commercial Earth Power	December, 1995
City of Winnipeg Power Smart Agreement	September, 2002
Commercial HVAC	September, 2003
Commercial Building Optimization	April, 2006
Commercial Refrigeration	April, 2006
Commercial Kitchen Appliances	January, 2008
Commercial Network Energy Management	May, 2008
Commercial Clothes Washers	July, 2008
Commercial New Buildings	April, 2009
Commercial C02 Sensors	April, 2009
INDUSTRIAL	
Performance Optimization	June, 1993
Natural Gas Optimization	September, 2006
CUSTOMER SELF-GENERATION	
Bioenergy Optimization	March, 2006
RATE/LOAD MANAGEMENT	
Curtailable Rates	November, 1993
DISCONTINUED/COMPLETED	
RESIDENTIAL DISCONTINUED/COMPLETED	
Outdoor Timer	October, 1989
Refrigerator/Freezer Buy-Back Pilot	1991/92
Residential Shower Head Pilot	1991/92
EE Water Savings Measures Component of the 'No Worry Plan'	November, 1996
EE Water Tank Measures Component of the 'No Worry Plan'	November, 1996
New Home	February, 2004
Compact Fluorescent Lighting	September, 2004
Seasonal LED Lighting	November, 2005
High Efficiency Furnace / Boiler	November, 2005
Residential Appliances	June, 2006
Programmable Thermostat Pilot	October, 2006
Energy Efficient Light Fixtures	October, 2006
Solar Hot Water Heating (Incentive Component)	November, 2008
COMMERCIAL DISCONTINUED/COMPLETED	
Roadway Lighting	April, 1991
Sentinel Lighting Conversion	April, 1991
Commercial Shower Head Pilot	1991/92
Infrared Heat Lamps	1991/92
Agricultural Demand Controller	July, 1992
Livestock Waterer	October, 1994
Commercial Construction - Air Barrier Component	December, 1995
Commercial Construction - Air Conditioning Component	December, 1995
Commercial Parking Lot Controllers	December, 1995
Agricultural Heat Pads	April, 1998
Commercial Rinse & Save	July, 2006
Power Smart Energy Manager*	November, 2008
Power Smart Shops*	February, 2009
INDUSTRIAL DISCONTINUED/COMPLETED	
High Efficiency Motor	September, 1991

* During 2012/13, this program was undergoing redesign.

Exhibit 2.3.1-B

Incentive-Based Power Smart Program Participation

PROGRAM	2012/13*	Cumulative
	Number of Participants	
RESIDENTIAL		
Water & Energy Saver	27,420	99,279
Refrigerator Retirement	8.,298	16,735
Home Insulation	2,867	31,512
Affordable Energy Program	1,653	6,615
	40,238	154,141
COMMERCIAL		
Commercial Lighting	748	12,357
Commercial Refrigeration	565	729
Commercial Building Envelope	337	2,160
Commercial HVAC/ C02 Sensors	93	695
Internal Retrofit	29	1,289
Commercial Custom Measures	27	69
Commercial Clothes Washers	17	244
Commercial New Buildings	15	22
Commercial Earth Power	10	119
Commercial Kitchen Appliances	6	81
Commercial Building Optimization	2	9
City of Winnipeg Power Smart Agreement	1	322
Commercial Network Energy Manager	0	8
	1,850	18,104
INDUSTRIAL		
Performance Optimization	71	677
Natural Gas Optimization	14	75
	85	752
DISCONTINUED/COMPLETED	46	500,728^
EFFICIENCY PROGRAMS SUBTOTAL	42,219	673,725
CUSTOMER SELF-GENERATION		
Bioenergy Optimization**	22	22
	22	22
RATE/LOAD MANAGEMENT		
Curtailable Rates**	3	5
	3	5
TOTAL	42,244	673,752

* Participation is defined as one household for residential programs, one project for commercial/industrial programs.

* * Participation represents the number of customers who participate each year. The cumulative number represents the actual number of unique customers who have participated.

^ This includes 343,381 participants of the Residential Compact Fluorescent Lighting Program.

Notes: This table includes electric and natural gas Power Smart participants.
Customers may participate in more than one Power Smart program and are counted multiple times, except for Bioenergy Optimization and Curtailable Rates.
Participation is measured by number of completed projects, and excludes free drivers and market transformation.

2.3.2 Residential Programs

The residential programs are established to serve residential customers throughout the province.

New Home Program

The New Home Program provided information and financial incentives for residential new construction, using measures such as lighting, insulation, ventilation, water technologies and improved building envelop.

In December 2010, the Manitoba Building code was modified to include water and energy efficiency minimum levels that were nearly equivalent to the New Home Program's Power Smart Gold Standard. As a result, the New Home Program closed to new registrants on February 28th, 2011 with a deadline to complete and certify a home by the program end date of February 28th, 2012. Although new homes were certified before the program end date, one was certified and rebated February 5th, 2013. As a result, the savings and incentives were allocated to the 2012/13 fiscal year. Manitoba Hydro continues to serve as the delivery agent for Natural Resources Canada's R-2000 Program.

Home Insulation Program

Information and financial incentives are offered to encourage owners of existing homes to upgrade their insulation to Power Smart levels.

Water & Energy Saver Program

The Water & Energy Saver Program offers free Water & Energy Saver kits to residential customers. Each kit contains a low-flow showerhead, low-flow faucet aerators, water heater pipe wrap and a refrigerator/freezer thermometer.

Affordable Energy Program

The Affordable Energy Program is designed to bring Power Smart and energy efficient measures to qualifying lower income households. The program leverages Manitoba Hydro Power Smart programs, the Affordable Energy Fund, the Federal Government ecoENERGY Program (until the program ended in March 2011), provincial government programs and existing community-based infrastructures. Energy efficiency measures include pre- and post- in-home energy evaluations, installation of basic energy efficiency items such as CFLs and low-flow showerheads, insulation upgrades and natural gas furnace upgrades.

Refrigerator Retirement Program

The Refrigerator Retirement Program provides residential customers with free in-home pick-up of their old, inefficient refrigerators and freezers, paying customers a $40 incentive for each appliance retired. This province-wide program is set run until March 2014.

First Nations Power Smart Program

Through the First Nations Power Smart Program, First Nations communities can improve the energy efficiency and comfort of their homes. The program provides each First Nations community a Manitoba Hydro energy efficiency specialist to recommend the installation of energy efficient measures. Participants are also provided insulation and basic energy efficiency upgrades. Community members are trained to conduct the upgrades and deliver the Power Smart program. And on request, energy saving seminars can be arranged for the community.

2.3.3 Commercial Programs

The commercial programs are established to serve commercial, institutional and industrial customers.

Commercial Lighting Program

The Commercial Lighting Program encourages commercial customers to install cost-effective energy efficient lighting systems. Manitoba Hydro also works with lighting distributors, installers, contractors and manufacturers to assist customers in saving electricity, and to ensure optimal lighting design based on use.

Commercial Building Optimization Program

The Commercial Building Optimization Program encourages commercial customers with existing buildings to use an investigation and adjustment process known as retro-commissioning to help return their buildings to their intended operating methods.

New Buildings Program

The New Buildings Program provides technical guidance and financial incentives for designing, constructing and operating new, energy efficient buildings in Manitoba.

Commercial Building Envelope Program

The Building Envelope Program encourages building owners to install window systems and/or insulation levels that meet Power Smart levels in their renovation or new building plans, and helps to reduce air leakage. Upgrading a building's envelope can reduce air leakage which will affect energy costs to heat and cool the building, while providing improved thermal comfort for occupants and improve indoor air quality.

Internal Retrofit Program

Energy efficiency in Manitoba Hydro buildings is encouraged by retrofitting existing and constructing new buildings to Power Smart levels.

Commercial HVAC Program

The Commercial HVAC Program encourages the use of high efficiency heating, ventilation and cooling systems, such as near-condensing and condensing boilers, CO2 sensors and energy efficient water-cooled chillers.

Commercial Earth Power Program

This program provides information and financial incentives to customers who install a geothermal heat pump system to offset a conventional electric heating system in commercial buildings.

Commercial Refrigeration Program

This program encourages grocery stores and restaurants to install energy efficient refrigeration equipment for their walk-ins, display cases and mechanical rooms to reduce energy consumption and create a more comfortable environment for their customers.

Commercial Kitchen Appliances Program

The Commercial Kitchen Appliances Program encourages customers to upgrade to ENERGY STAR® qualified steamers and fryers.

Commercial Clothes Washers Program

The Commercial Clothes Washers Program encourages customers to install energy efficient front-loading clothes washers at their business or facility.

Custom Measures Program

The Custom Measures Program encourages commercial customers who are renovating, undergoing plant expansion or building new facilities to improve system performance by installing or upgrading technologies such as direct digital controllers, variable frequency drives and heat recovery ventilation systems. The program is designed to serve customers undertaking energy efficient projects that are not specifically supported by the other existing Power Smart programs.

Network Energy Management Program

The Network Energy Management Program encourages the installation of network management software. The software shuts down PCs when they are inactive while still allowing network administrators to perform regular maintenance tasks, such as software upgrades and security patches.

City of Winnipeg Power Smart Agreement

The City of Winnipeg Power Smart Agreement was established as part of the Winnipeg Hydro purchase agreement to encourage and implement energy saving measures in city-owned facilities. The Power Smart Agreement encompasses electricity, natural gas and water saving measures for both new construction and renovation projects. The terms of the agreement ended in September 2012.

2.3.4 Industrial Programs

The industrial programs are established to serve the industrial customers throughout the province to encourage the optimization and efficiency of their processes.

Performance Optimization Program

The Performance Optimization Program encourages industrial and large commercial customers to study and implement energy efficiency measures in their electro-technology processes and motor-drive systems.

Natural Gas Optimization Program

This program provides industrial and large commercial customers with the technical support and financial incentives necessary to identify, investigate and implement systematic efficiency improvements in the natural gas-fired systems throughout their facilities.

2.3.5 Rate/Load Management Programs

Curtailable Rates Program

Large industrial customers are provided with monetary incentives by way of a monthly credit on their electricity bill in exchange for having electrical load available for curtailment if called upon by Manitoba Hydro.

2.3.6 Customer Self-Generation Programs

Bioenergy Optimization Program

This program encourages industrial customers to install, operate and maintain generation equipment at their site in order to displace their internal load.

3.0 Power Smart Success Stories

Power Smart Designation Awarded to Sturgeon Heights Community Centre

On April 16, 2012 Manitoba Hydro congratulated Sturgeon Heights Community Centre with a plaque, for achieving the Power Smart designation, resulting in energy performance of over 33% more efficient than a convention community centre.

Made possible in part due to technical and financial support from Manitoba Hydro, the energy efficient design of the community centre is estimated to achieve annual energy savings of nearly 60,000 kW.h of electricity and 30,000 cubic meters of natural gas. It is anticipated that the building will save approximately $10,000 annually in energy costs. Also achieved, a greenhouse gas emissions reduction of 100 tonnes of CO2e annually, which is equivalent to taking 20 cars off the road each year.

Energy efficient features of the building include a high efficiency condensing natural gas boiler, a ventilation heat recovery system, demand control ventilation, water-saving fixtures, energy efficient lighting and controls, and high levels of insulation in the roof, walls and floor slabs.

Makoonsag Intergenerational Children's Centre earns Power Smart Designation

In Spring 2012, Manitoba Hydro Power Smart helped celebrate the grand opening event for the newly constructed Makoonsag Intergenerational Children's Centre in Winnipeg. Manitoba Hydro delivered a Power Smart designation plaque to congratulate the customer for building to Power Smart Design Standards, resulting in energy performance of over 40% more efficient than a conventional building.

The 10,000 square foot complex is significantly more efficient than a standard day care facility. Energy efficient features of the building include a unique air-source heat pump for the building's heating and cooling, a ventilation heat-recovery system, water-saving fixtures, energy efficient lighting and controls coupled with strategic use of day lighting, and high levels of insulation in the roof, walls and floor slabs.

Services at the centre are directed to Aboriginal and new immigrant families, providing positive reinforcement and educational support that will help improve the future for children and families in Winnipeg. The child-care and intergenerational learning centre employs 12 child-care workers and two instructors in early childhood education.

Hutterite Colonies Making the Switch to Geothermal

The Province of Manitoba announced an Emissions Tax on coal as part of the Climate Change Action Plan in 2011. Rather than those colonies who are using coal switch to electric furnaces or baseboards, alternate heating sources were explored including bringing in natural gas lines, biomass and geothermal heat pumps. Concurrently, colonies using conventional electric heating sources were also looking to reduce their heating costs.

The Commercial Geothermal Program was able to assist 11 colonies across 25 projects by pre-approving over $420,000 in incentives for switching their conventional electric heating system or coal source to geothermal heat pumps.

Clearspring Middle School Builds to Power Smart Design Standards

The Hanover School Division officially opened the doors to its newest facility, Clearspring Middle School, on November 7th, 2012. At the opening, Manitoba Hydro presented a Power Smart plaque to the school.

Manitoba Hydro was included throughout the school's integrated design process and helped the Hanover School Division achieve its goal of building a school that, itself, serves as a learning tool for students. The school is designed with a systems approach regarding energy performance and its efficiencies are the result of many energy conservation features working together.

Energy conservation features include a site orientation that optimizes solar gain and day lighting strategies, a high performance building envelope, material selection that emphasizes durability and reduced environmental impact, in-floor heating with individual zone controls, a closed-loop geothermal ground source heat pump, economizers on the air handlers, carbon dioxide monitors and high-efficiency lighting systems with occupancy sensors. A measurement and verification plan is also in place to assist with ongoing energy management and optimization of building energy and water performance over time. Overall, the school is targeting 67% baseline energy consumption.

Power Smart for Business Customer Receives Environmental Leadership Award

The Assiniboine Credit Union's commitment to environmental leadership has been recognized with a Manitoba Excellence in Sustainability Award of Action on Climate Change, Air Quality and Energy Efficiency. The award was presented by the Manitoba Round Table for Sustainable Development, and celebrates sustainability leaders across the province.

Manitoba Hydro supported Assiniboine Credit Union's nomination, in part because of the credit union's extensive involvement with energy efficiency through the Power Smart for Business programs.

Assiniboine Credit Union built its new facilities to Manitoba Hydro's Power Smart Design Standards, making them at least 25% more efficient that a conventional building.

Assiniboine Credit Union's energy efficiency upgrades include insulation upgrades, energy efficient windows, and high-efficiency lighting and use of light-emitting diode lighting technology (LED) for interior light and exterior signage. These upgrades resulted in estimated annual savings of $20,000 and reduction of 300 tonnes of CO_2e emissions, equivalent to taking 60 cars off the road per year.

Manitoba Hydro Places Second in the 2012 E Source Utility Ad Contest

Manitoba Hydro was awarded second place for the "Best Outdoor Ad" in the 2012 E Source Utility Ad Awards Contest. The ad contest was open to U.S. and Canadian electric and gas companies, receiving more than 600 advertisement submissions, a record number of entries.

Manitoba Hydro Place wins Global Award for Land Use

Manitoba Hydro Place was one of fourteen developments from around the world selected as winners of the 2012 Urban Land Institute (ULI) Global Awards for Excellence competition as announced on October 19, 2012 in Denver, Colorado.

The competition, now in its 34th year, works to promote best practices in all types of real estate development. Selected from nearly 200 entries throughout the world, Manitoba Hydro Place, along with other winning projects, was found to demonstrate ingenuity, innovation and long-term thinking that can be embraced in other scenarios.

"This year's 14 ULI Global Award winners are from eight countries and represent a broad array of property types and uses," said competition jury chairman Randall Rowe. "They are dramatic examples of applying ULI best practices to real estate development and their enduring impact on diverse communities across the globe."

Manitoba Hydro Place to Contribute to Development of Healthy Society

Manitoba Hydro Place recently won a 2012 International Green Good Design Award which recognizes only those designs expected to contribute to the development of a healthy society.

Griffin Wheel's Compressed Air Optimization

Griffin Wheel has substantially improved their air system reliability and reduced their compressed air operating costs by following the recommendations of Manitoba Hydro. The company has reduced the electrical air system operating costs by 44% by replacing three of their four air compressors with high efficiency units, and implementing other compressed air related equipment improvements. The old air compressors were consuming 4.1 GW.h annually with a 0.5 MW peak demand, costing $202,000 in annual electric operating costs. On recommendation from Manitoba Hydro, the company purchased three new efficient two-stage water cooled rotary screw air compressors including one with variable speed drive technology. The compressors were set up on a control system that coordinates the operation of the compressors by constantly choosing the best and most efficient compressors suited for the various compressed air flows occurring over the normal production schedule. Compressed air filters were upgraded to allow more efficient operation at lower pressures and to improve air quality. Cycling air dryers were also installed to use less energy than standard dryers. A large number of plant leaks were repaired to reduce the compressed air waste, including one very large leak caused by the failure of a dust collector. The project costs were $671,000 and were supported by a Performance Optimization Power Smart incentive of $250,000. The project has been completed and is expected to pay itself back in less than three years.

As a result of the changes, the compressed air system is now consuming 2.3 GW.h annually with a peak demand of 0.3 MW. Operating costs have fallen to $112,300 per year. This does not include the savings associated with the rental compressors that are no longer required. Additional benefits include more stable plant pressure, increased equipment reliability and reduced maintenance costs.

University of Manitoba's Parker Building Improves Vacuum System

In summer 2012, the University of Manitoba benefited from Manitoba Hydro's Performance Optimization Program by upgrading the inefficient vacuum system in the Parker Building.

The 50 hp vacuum at the Parker Building had been operating continuously even though the vacuum loading was variable. Associated electrical costs amounted to $14,881 per year. The system was a good candidate for a machine and controls upgrade, combined with a leak reduction campaign in the distribution system.

With incentives from Manitoba Hydro, the University upgraded to a new vacuum system consisting of three individual 30 hp units, operating in a staged manner according to vacuum demand.

The new electrical operating costs are calculated to be $8,106 per year, providing annual savings of $6,774. Energy and demand savings are 138,719 kW.h and 15.8 KW respectively.

Total project costs were $151,195, and a maximum incentive of $27,483 is scheduled for payment.

4.0 Market Results

In the past, the success of Manitoba Hydro's Power Smart initiative was evaluated based on DSM incentive-based program activity alone. However, the true impact of Power Smart also includes the impact of the programs on the market as a whole, or market transformation. Although, market transformation is more difficult to measure. Manitoba Hydro has made significant in-roads in developing program-specific methodologies for measuring Power Smart's impact. Wherever possible, Manitoba Hydro has attempted to obtain sales/technology-specific data to calculate a program's true impact. In some instances, qualitative information is used to determine a program's impact on the market. Manitoba Hydro plans on continuing to further quantify and report the influence of market transformation within the Manitoba marketplace.

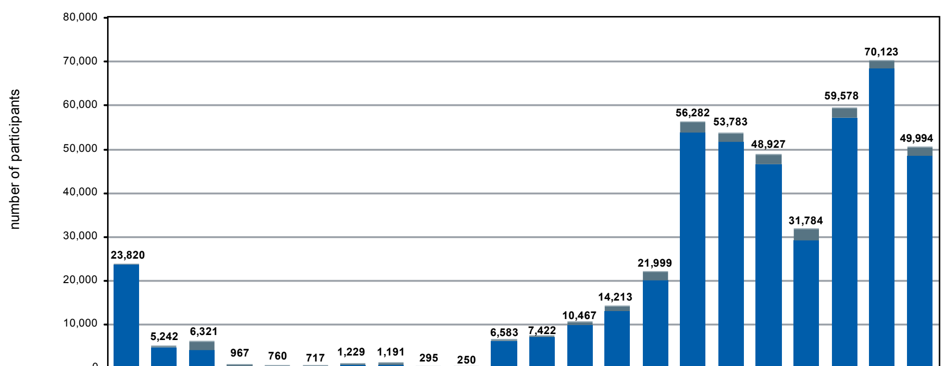
4.1 Power Smart Portfolio Results

The following sections provide an overview of Power Smart portfolio results to date.

4.1.1 Participation in Power Smart Programs

The following graph outlines total Power Smart participation in incentive-based programs, DSM support programs and cost-recovery programs with participation presented by sector (i.e. residential, commercial and industrial programs).

Exhibit 4.1.1
Power Smart Program Participation



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Industrial	24	157	202	229	185	182	195	8	4	9	17	25	32	48	50	49	81	99	116	90	73	110
Commercial	65	273	1,959	738	575	334	325	502	291	241	305	364	538	1,020	1,849	2,364	2,041	2,136	2,491	2,256	1,526	1,895
Residential (excluding CFLs)	23,731	4,812	4,160	0	0	201	709	681	0	0	6,261	7,033	9,897	13,145	20,100	53,869	51,661	46,692	29,177	57,232	68,524	47,989
Total Achieved (excluding CFLs)	23,820	5,242	6,321	967	760	717	1,229	1,191	295	250	6,583	7,422	10,467	14,213	21,999	56,282	53,783	48,927	31,784	59,578	70,123	49,994

Note: Includes electric and natural gas participants of DSM support programs, cost recovery and incentive-based programs.
Participation for codes and standards is excluded.
Curtailable Rates Program participation is included in the industrial sector.
Customers may participate in more than one Power Smart program.
The 343,381 sales under the Residential Compact Fluorescent Lighting Program during 2004/05-2010/11 are excluded.
Figures may not add due to rounding.

As displayed in the preceding graph, participation in Manitoba Hydro's Power Smart programs continues to be strong. During 2012/13, there were nearly 50,000 participants in Power Smart DSM support programs and incentive-based programs. Excluding the Residential Compact Fluorescent Lighting Program, there have been approximately 472,000 participants cumulatively.

Participation of the Residential Compact Fluorescent Program has been excluded to provide a better indication of participation trends. The Residential Compact Fluorescent Program provided a low-cost option for achieving energy efficiency, and represented 44% of residential Power Smart participation and 42% of overall Power Smart participation.

Refer to APPENDIX C for historical Power Smart participation.

4.1.2 Power Smart Portfolio - Impact of Electric Programs

The following tables outline the electricity savings achieved by the Power Smart portfolio during 2012/13 and provide a comparison between achieved results and planned targets, where applicable:

Exhibit 4.1.2-A

Annual GW.h Savings (at generation) - Power Smart Portfolio

	2012/13 Actual	2012/13 Plan^	Total*
INCENTIVE-BASED PROGRAMS	256	104	1,612
CODES & STANDARDS	75	66	628
DSM SUPPORT PROGRAMS	1	3	29
OVERALL IMPACT	332	173	2,269

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

Exhibit 4.1.2-B

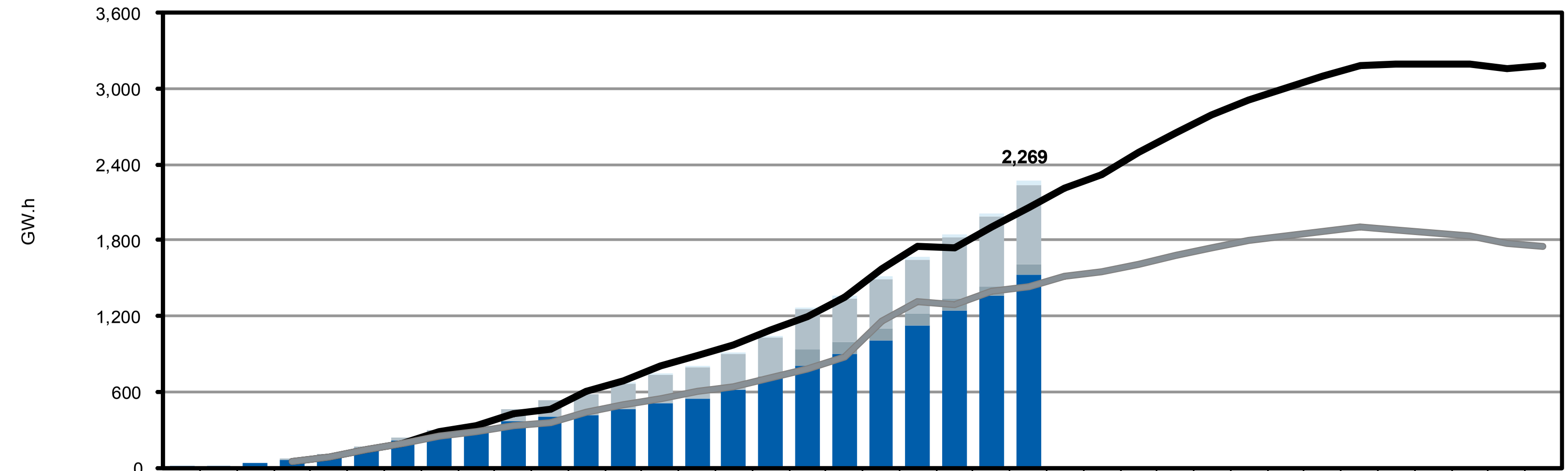
Annual Average Winter MW Savings (at generation) - Power Smart Portfolio

	2012/13 Actual	2012/13 Plan^	Total*
INCENTIVE-BASED PROGRAMS	201	184	477
CODES & STANDARDS	19	16	150
DSM SUPPORT PROGRAMS	1	1	10
OVERALL IMPACT	221	200	637

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: MW savings are based on the average of the winter AM & PM system peak savings.
For the Curtailable Rates Program, MW savings reported is expected curtailable load on system at the time a curtailment occurs.
Figures may not add due to rounding.

The following graphs present the electric energy and demand savings achieved to date by the Power Smart portfolio and the corresponding targets.

Exhibit 4.1.2-C
Electric Energy Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation

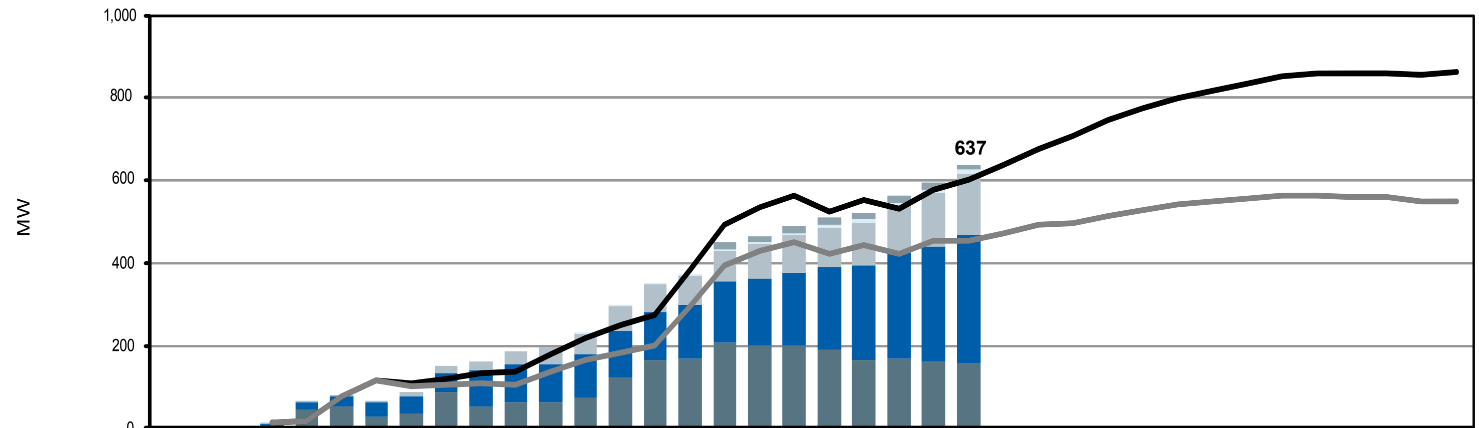


	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08
DSM Support Programs													2	4	7	11	13	16	20
Codes & Standards	-	-	-	2	8	16	25	40	63	93	125	156	189	228	248	274	298	323	352
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	132	93
Incentive-Based - Efficiency	6	10	31	59	99	151	209	259	285	363	407	419	467	511	546	620	715	799	895
Plan	-			50	86	138	195	281	336	422	466	602	686	810	891	970	1,088	1,199	1,350
Plan (Incentive-Based Programs only)	-			50	86	138	195	252	279	327	350	435	491	544	603	634	713	782	879
Total Achieved	6	10	31	62	107	167	235	299	348	456	532	575	659	743	801	904	1,037	1,270	1,359

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	22	25	26	27	29														
Codes & Standards	382	430	481	553	628														
Incentive-Based - Customer Self Generation	103	88	95	77	91														
Incentive-Based - Efficiency	1,002	1,126	1,243	1,356	1,521														
Plan	1,569	1,753	1,736	1,906	2063	2214	2323	2489	2654	2787	2906	3003	3096	3184	3195	3191	3186	3157	3175
Plan (Incentive-Based Programs only)	1,157	1,310	1,293	1391	1,427	1,509	1,551	1,608	1,675	1,737	1,796	1,835	1,871	1,902	1,881	1,858	1,832	1,771	1,754
Total Achieved	1,509	1,669	1,846	2,014	2,269														

Note: Targeted savings are unadjusted for programs not running or other revisions.
Figures may not add due to rounding.

Exhibit 4.1.2-D
Average Winter Demand Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan
at generation



	89/90	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
DSM Support Programs													1	1	2	3	3	4	6	6
Codes & Standards	-	-	-	1	2	4	6	10	15	23	32	40	49	59	64	70	76	82	89	97
Incentive-Based - Customer Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16	16	16
Incentive-Based - Efficiency	0	1	4	10	17	26	34	42	46	86	91	93	105	113	119	131	146	162	179	200
Incentive-Based - Rate/Load	-	-	-	-	45	51	27	36	88	53	64	63	75	121	163	169	208	202	199	190
Plan				12	18	75	114	108	118	134	135	178	216	249	273	385	491	535	564	524
Plan (Incentive-Based Programs only)				12	18	75	114	101	104	110	105	136	166	183	200	296	394	429	449	421
Total	0	1	4	10	64	80	68	87	149	162	187	196	230	295	348	373	450	466	488	509

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs	8	9	9	10														
Codes & Standards	105	113	131	150														
Incentive-Based - Customer Self Generation	16	16	16	10														
Incentive-Based - Efficiency	229	254	276	308														
Incentive-Based - Rate/Load	164	170	162	159														
Plan	551	531	578	603	638	674	707	746	773	798	816	835	852	858	858	859	856	861
Plan (Incentive-Based Programs only)	442	421	454	454	472	492	498	513	527	540	548	556	563	563	561	559	550	550
Total	521	562	594	637														

Note: Targeted savings are unadjusted for programs not running or other revisions.
Figures may not add due to rounding.

Cumulatively, the entire Power Smart portfolio has saved 2,269 GW.h and 637 MW (at generation), 10% and 6% above their respective targets.

4.1.3 Power Smart Portfolio - Impact of Natural Gas Programs

The following table and graph present natural gas savings achieved by the Power Smart portfolio:

Exhibit 4.1.3 - A
Annual Natural Gas Savings

	2012/13 Actual	2012/13 Plan^	Total*
	millions of cubic metres		
PROGRAM & INITIATIVE			
Incentive-Based Programs	11.3	7.9	62.2
Codes & Standards	3.4	2.7	13.2
DSM Support Programs	0.6	0.5	20.3
	15.3	11.1	95.7
INTERACTIVE EFFECTS			
Incentive-Based Interactive Effects	(0.7)	(1.1)	(12.0)
NET IMPACT OVERALL	14.6	10.0	83.6

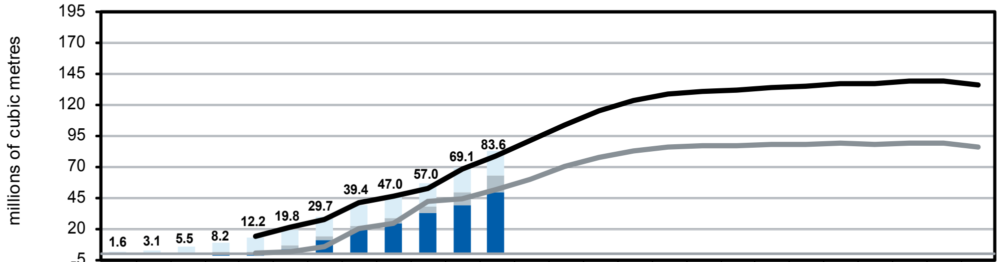
^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

The Power Smart portfolio provided natural gas savings of 15.3 million cubic metres in 2012/13, which was 38% more than planned.

Some electric Power Smart programs result in an increase or decrease in natural gas consumption (interactive effects). For example, a more energy efficient lighting system emits less heat, requiring more energy to heat the space. In cases where the heat is produced through electric heating sources, interactive effects are taken into account when calculating the anticipated electricity savings that will result from the program. In cases where the heat is produced through natural gas heating systems, the interactive effects are taken into account when determining the natural gas savings. These interactive effects represent the increase in natural gas consumption for gas-heated homes resulting from the installation of energy efficient lighting systems.

After interactive effects, the Power Smart portfolio achieved net natural gas savings of 14.6 million cubic metres in 2012/13, 46% more than planned.

Exhibit 4.1.3-B
Integrated Natural Gas Savings - Power Smart Portfolio
Total Savings Achieved vs. Plan



	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
DSM Support Programs	1.2	2.4	4.3	7.7	11.3	13.2	15.3	16.4	18.3	19.0	19.7	20.3
Codes & Standards	0.3	0.7	1.1	1.6	2.0	2.4	2.7	3.0	3.5	4.4	9.9	13.2
Incentive-Based Integrated	0.0	0.1	0.1	-1.0	-1.0	4.3	11.7	20.0	25.3	33.5	39.6	50.1
Integrated Plan					14.8	21.5	27.9	41.4	46.3	52.8	68.6	79.6
Integrated Plan (Incentive-Based Programs only)					0.8	1.9	5.7	20.8	24.6	42.2	44.7	51.5
Total Achieved	1.6	3.1	5.5	8.2	12.2	19.8	29.7	39.4	47.0	57.0	69.1	83.6

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
DSM Support Programs														
Codes & Standards														
Incentive-Based Integrated														
Integrated Plan	91.8	105.1	116.1	124.6	128.8	131.0	132.7	134.5	136.0	137.6	138.0	139.8	140.2	137.5
Integrated Plan (Incentive-Based Programs only)	60.5	70.5	78.1	83.1	86.2	87.2	87.7	88.4	88.8	89.3	88.7	89.8	89.7	86.4
Total Achieved														

Note: Targeted savings are unadjusted for programs not running or other revisions. Figures may not add due to rounding.

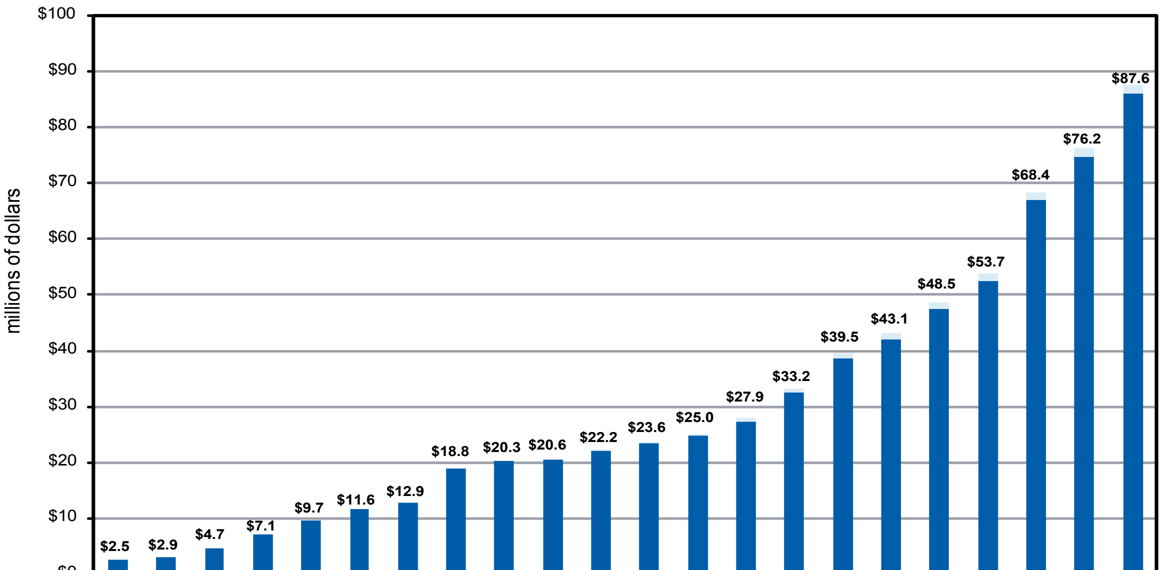
To date, after interactive effects, the Power Smart portfolio has saved nearly 84 million cubic metres of natural gas, 5% above target.

4.1.4 Customer Bill Reduction

Electricity Bill Reduction

When customers save electricity through Manitoba Hydro's Power Smart programs, it translates into lower electricity bills for participating customers. Displayed in Exhibit 4.1.4-A are the annual customer bill reductions resulting from DSM support programs and incentive-based Power Smart program electric savings to date.

Exhibit 4.1.4-A
Customer Electricity Bill Reduction (2012$)
millions of dollars



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
DSM Support Program Savings	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	$0.3	$0.5	$0.6	$0.8	$1.0	$1.1	$1.3	$1.4	$1.4	$1.5
Incentive-Based Savings	$2.5	$2.9	$4.7	$7.1	$9.7	$11.6	$12.9	$18.8	$20.3	$20.6	$22.1	$23.5	$24.7	$27.4	$32.6	$38.7	$42.1	$47.4	$52.4	$67.0	$74.8	$86.1
Total	$2.5	$2.9	$4.7	$7.1	$9.7	$11.6	$12.9	$18.8	$20.3	$20.6	$22.2	$23.6	$25.0	$27.9	$33.2	$39.5	$43.1	$48.5	$53.7	$68.4	$76.2	$87.6

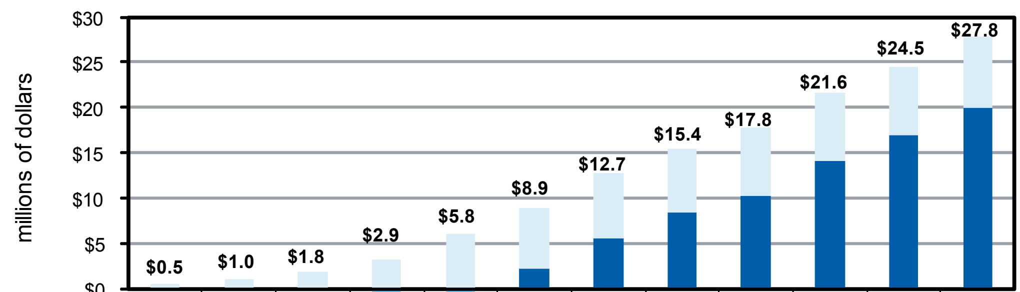
Note: Bill reductions exclude savings due to codes & standards.
Demand savings resulting from the Curtailable Rates Program are excluded from this analysis.
Figures may not add due to rounding.

Power Smart DSM support programs and incentive-based programs saved participating customers nearly $88 million in 2012/13 and over $660 million cumulatively on their electricity bills.

Natural Gas Bill Reduction

Customers also save on their natural gas bills when participating in certain Power Smart initiatives. Exhibit 4.1.4-B displays annual customer bill reductions resulting from Power Smart natural gas savings to date (net of interactive effects).

Exhibit 4.1.4-B
Customer Natural Gas Bill Reduction (2012$)
millions of dollars



	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
DSM Support Programs Savings	$0.5	$1.0	$1.8	$3.2	$6.1	$6.8	$7.2	$7.1	$7.6	$7.6	$7.7	$7.9
Incentive-Based Savings	$0.0	$0.0	$0.1	-$0.3	-$0.3	$2.1	$5.5	$8.4	$10.2	$14.0	$16.9	$19.9
Total	$0.5	$1.0	$1.8	$2.9	$5.8	$8.9	$12.7	$15.4	$17.8	$21.6	$24.5	$27.8

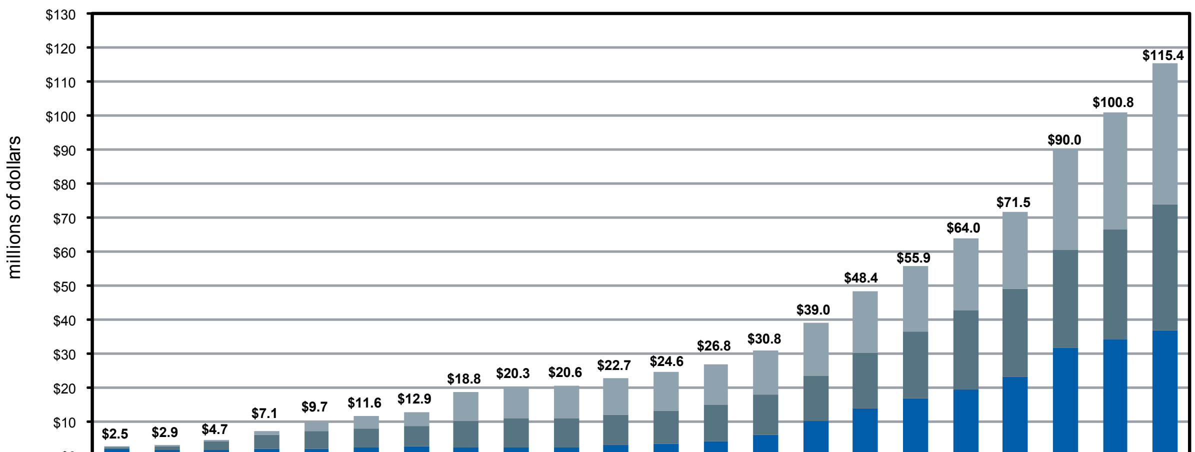
Note: Bill reduction excludes savings due to codes & standards.
Interactive effects in 2012/13 resulted in a $4.8 million increase in customer bills, which is captured within incentive-based savings.
Natural gas bill reduction includes primary and distribution rates only.
Figures may not add due to rounding.

As a result of Power Smart initiatives, participating customers saved nearly $28 million in 2012/13, and approximately $141 million cumulatively on their natural gas bills.

Combined Bill Reduction

The following graph presents the annual combined customer bill reduction for participants of Power Smart DSM support programs and incentive-based programs by sector. Savings include those from both electric and natural gas initiatives.

Exhibit 4.1.4-C
Combined Electricity & Natural Gas Customer Bill Reduction (2012$)
Total Annual Reductions by Sector
millions of dollars



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02
Industrial	$0.0	$0.3	$0.4	$1.1	$2.5	$3.7	$4.2	$8.8	$9.5	$9.5	$10.6
Commercial	$0.5	$1.2	$2.6	$4.0	$5.1	$5.6	$6.1	$7.5	$8.3	$8.6	$9.1
Residential	$2.0	$1.4	$1.7	$2.0	$2.1	$2.4	$2.6	$2.5	$2.5	$2.5	$3.0
Total	$2.5	$2.9	$4.7	$7.1	$9.7	$11.6	$12.9	$18.8	$20.3	$20.6	$22.7

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Industrial	$11.5	$11.9	$12.9	$15.4	$18.4	$19.6	$21.4	$22.3	$29.6	$34.4	$41.5
Commercial	$9.6	$10.6	$11.6	$13.4	$16.2	$19.4	$23.0	$26.2	$28.7	$32.0	$36.9
Residential	$3.5	$4.3	$6.2	$10.2	$13.8	$16.9	$19.5	$23.0	$31.7	$34.4	$36.9
Total	$24.6	$26.8	$30.8	$39.0	$48.4	$55.9	$64.0	$71.5	$90.0	$100.8	$115.4

Note: Bill reductions exclude savings due to codes & standards.
Demand savings resulting from the Curtailable Rates Program are excluded from this analysis.
Natural gas bill reduction includes primary and distribution rates only.
Figures may not add due to rounding.

Power Smart DSM support programs and incentive-based programs saved participating customers over $115 million in 2012/13 alone. These savings are distributed relatively evenly between industrial, commercial and residential customers.

Cumulatively, participating customers have saved over $801 million on electricity and natural gas bills. To date, industrial, commercial and residential customers have reduced their bills by 36%, 36% and 28% respectively.

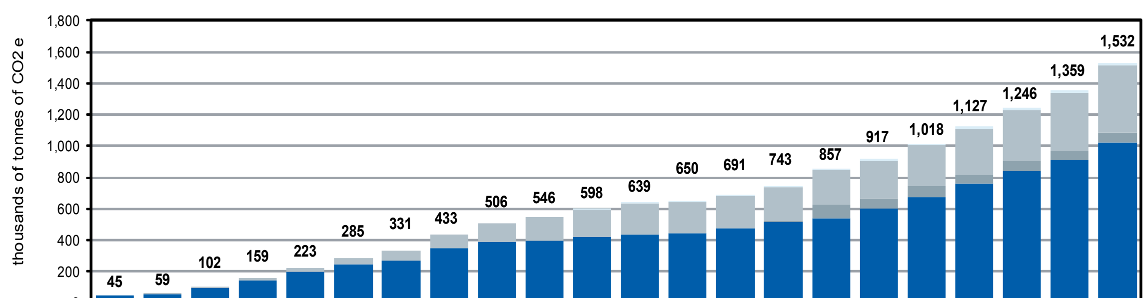
4.1.5 Power Smart Program Impact on Greenhouse Gas Emissions

The energy efficiency measures and improvements installed through Manitoba Hydro's Power Smart programs reduce the amount of greenhouse gas and other air polluting emissions indirectly from power generation, and directly from the transmission and distribution of natural gas, and will continue to do so over their product lives. Both electricity and natural gas consumption reductions have a positive impact on global greenhouse gas emissions.

Impact of Electricity Savings

As Manitobans conserve electric energy through Power Smart programs, more hydro electricity is available for export. These exports displace coal and natural gas fuelled generation outside of Manitoba, which results in significant global reductions of greenhouse gases and other emissions. Therefore, the impact of Power Smart programs on global greenhouse gas emissions is quantified based on estimates of reduced coal and natural gas fuelled generation outside the province, and is measured in carbon dioxide equivalent emissions. Because the emission reductions do not occur at the site of the participating customer, these reductions are referred to as *indirect* emission reductions. Exhibit 4.1.5-A shows the equivalent reduction in carbon dioxide emissions resulting from Power Smart electric program activity to date.

Exhibit 4.1.5-A
Total Annual Indirect Greenhouse Gas Emission Reductions due to Electric Savings
thousands of tonnes of CO2e



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
DSM Support Programs savings	-	-	-	-	-	-	-	-	-	-	2	3	6	8	10	11	13	15	17	18	18	20
Codes & Standards	-	2	7	15	24	38	60	88	119	149	172	196	201	209	213	218	237	258	290	325	373	424
Self Generation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	89	63	70	59	64	52	61
Incentive based savings	45	56	95	144	199	246	271	345	387	398	424	439	444	474	512	539	604	676	760	839	915	1,027
Total	45	59	102	159	223	285	331	433	506	546	598	639	650	691	743	857	917	1,018	1,127	1,246	1,359	1,532

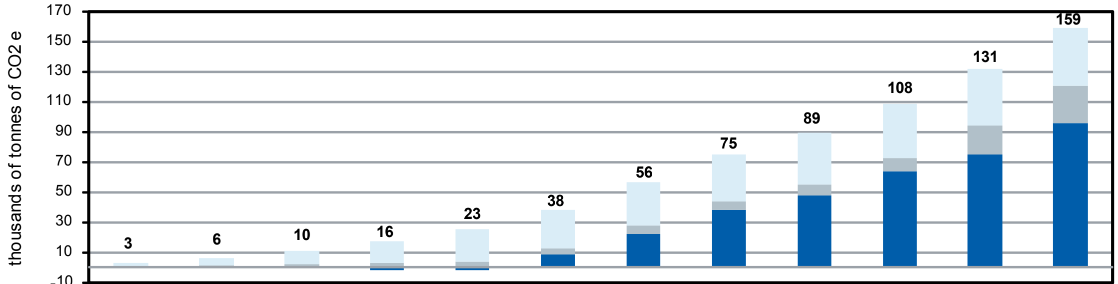
Note: Figures may not add due to rounding.

The 2,269 GW.h savings resulting from electric Power Smart program activity and codes and standards initiatives to date have displaced greenhouse gas emissions by nearly 1,532 thousand tonnes of carbon dioxide equivalent emissions. This is comparable to removing 306 thousand cars off the road for one full year.

Impact of Natural Gas Savings

Power Smart natural gas programs result in *direct* emission reductions at the location of the participating customer. The following chart displays direct greenhouse gas reductions resulting from lower natural gas consumption in Manitoba.

Exhibit 4.1.5-B
Total Annual Direct Greenhouse Gas Emission Reductions due to Natural Gas Savings
thousands of tonnes of CO2e



	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
DSM Support Programs savings	2	5	8	15	21	25	29	31	35	36	37	39
Codes & Standards	1	1	2	3	4	5	5	6	7	8	19	25
Incentive-based savings	0	0	0	-2	-2	8	22	38	48	64	75	95
Total	3	6	10	16	23	38	56	75	89	108	131	159

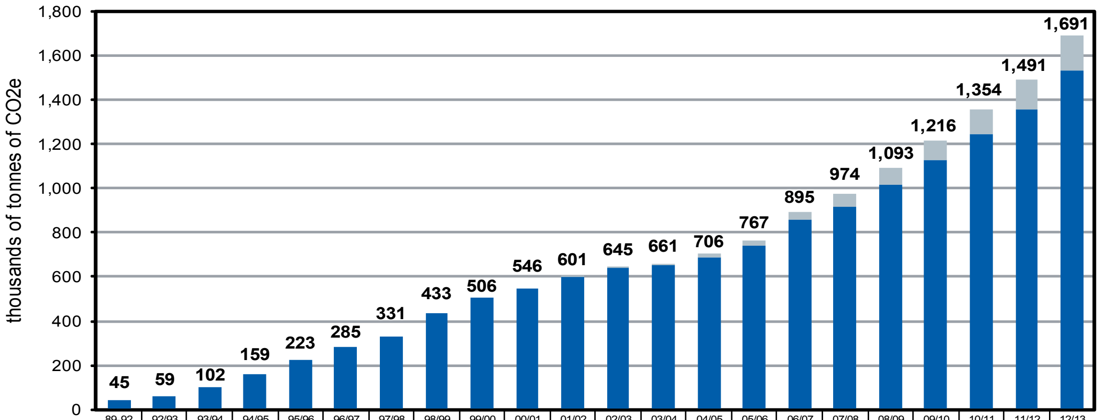
Note: Figures may not add due to rounding.

The 84 million cubic metres of reduced natural gas consumption (after interactive effects) from Power Smart programs to date has displaced approximately 159 thousand tonnes of greenhouse gas emissions. This is equivalent to removing 31 thousand vehicles off the road for one full year.

Combined Impact of Electricity and Natural Gas Savings

The following graph presents the greenhouse gas emission reductions that have resulted from all electric and natural gas Power Smart program activity to date.

Exhibit E.4.1.5-C
Total Annual Greenhouse Gas Emission Reductions
Due to Electric & Natural Gas Savings
thousands of tonnes of CO2e



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Natural Gas											3	6	10	16	23	38	56	75	89	108	131	159
Electric	45	59	102	159	223	285	331	433	506	546	598	639	650	691	743	857	917	1,018	1,127	1,246	1,359	1,532
Total	45	59	102	159	223	285	331	433	506	546	601	645	661	706	767	895	974	1,093	1,216	1,354	1,491	1,691

Note: Figures may not add due to rounding.

The 2,269 GW.h savings from electricity and 84 million cubic metres savings from natural gas Power Smart programs have resulted in greenhouse gas emission reductions of approximately 1,691 thousand tonnes of carbon dioxide equivalent emissions. This is comparable to removing nearly 338 thousand vehicles off the road for one full year.

4.2 DSM Support Programs & Cost-Recovery Programs

4.2.1 Annual Energy & Demand Savings from DSM Support Programs & Cost-Recovery Programs

Exhibits 4.2.1-A through 4.2.1-C provide an overview of the estimated electricity and natural gas savings achieved to 2012/13 through DSM support programs and cost-recovery programs, for those programs where energy savings can be reasonably measured or estimated using engineering calculations.

Exhibit 4.2.1 - A

Annual GW.h Savings - Electric DSM Support Programs & Cost-Recovery Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan^
RESIDENTIAL				
Power Smart Residential Loan	0.6	0.3	8.4	12.9
Residential Earth Power Loan	0.5	1.6	13.3	35.7
Power Smart Residential PAYS Program	0.0	0.5	0.0	9.1
ecoENERGY	-	-	0.8	0.8
	1.1	2.4	22.5	58.5
COMMERCIAL				
Power Smart for Business PAYS Program	-	-	-	2.1
	-	-	-	2.1
DISCONTINUED/COMPLETED PROGRAMS	-	0.0	3.0	2.4
	-	0.0	3.0	2.4
TOTAL (at customer meter)	1.1	2.5	25.5	63.0
TOTAL (at generation)	1.3	2.8	29.1	71.8

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

Exhibit 4.2.1 - B

Average Winter MW Savings - Electric DSM Support Programs & Cost-Recovery Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan^
RESIDENTIAL				
Power Smart Residential Loan	0.3	0.2	4.7	7.1
Residential Earth Power Loan	0.1	0.4	3.9	9.0
Power Smart Residential PAYS Program	0.0	0.2	0.0	4.6
ecoENERGY	-	-	-	-
	0.4	0.8	8.6	20.7
COMMERCIAL				
Power Smart for Business PAYS Program	-	0.0	-	0.6
	-	-	-	0.6
DISCONTINUED/COMPLETED PROGRAMS	-	-	0.2	0.2
	-	-	0.2	0.2
TOTAL (at customer meter)	0.4	0.8	8.8	21.5
TOTAL (at generation)	0.5	0.9	10.0	24.5

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

Exhibit 4.2.1 - C

Annual m^3 Savings - Natural Gas DSM Support Programs & Cost-Recovery Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan^
RESIDENTIAL				
Residential Earth Power Loan	0.3	0.1	2.7	4.0
Power Smart Residential Loan	0.3	0.3	14.9	19.7
Power Smart Residential PAYS Program	(0.0)	0.1	(0.0)	3.4
ecoENERGY	-	-	2.3	2.3
	0.6	0.5	19.9	29.4
COMMERCIAL				
Power Smart for Business PAYS Program	-	0.0	-	0.1
	-	0.0	-	0.1
DISCONTINUED/COMPLETED PROGRAMS	-	-	0.3	0.4
	-	-	0.3	0.4
TOTAL	0.6	0.5	20.3	29.9

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.

4.3 Energy Efficiency Codes & Standards

In addition to DSM activities, some utilities, including Manitoba Hydro, are actively involved in a number of provincial and national committees. These committees work with governments and equipment manufacturers to gain acceptance of higher efficiency levels for various technologies, and to encourage adoption of energy efficiency standards and regulations.

Manitoba Hydro prepares an annual forecast of the expected influence of codes and standards, and since 1995, this forecast has been used to adjust Manitoba Hydro's system load forecast.

In many cases, legislation and regulations are the most effective and permanent form of market transformation, as it ensures customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Traditionally, changing legislation can be complex when faced with lack of market acceptance. These changes impact building design and construction, as well as industry manufacturing processes, and therefore do not always receive strong industry support without preceding market intervention (i.e. legislation and regulations).

4.3.1 National Activities

Manitoba Hydro is a key player on the CSA Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This committee is responsible for changes to national performance standards and legislation which have resulted in the improvement of energy utilization of numerous appliances and technologies. For example, as a result of SCOPEER working with Canadian manufacturers, refrigerator manufacturers now market products which exceed the current minimum efficiency standards for inter-provincial exporting.

Beginning in September 2005, Manitoba Hydro chaired the newly-created Manitoba Energy Code Advisory Committee which was tasked to provide recommendations for the adoption, development and implementation of energy efficiency requirements for all new commercial construction (i.e. new buildings, additions to existing buildings and major renovations of existing buildings) in Manitoba. In the report *"Building Energy, Building Leadership"*, the Committee recommended Manitoba adopt the Model National Energy Code for Buildings (MNECB) in the following three stages: (1) Adopt the MNECB (1997) as a regulation under The Buildings and Mobile Homes Act, (2) Develop and adopt Manitoba Amendments to the MNECB by January 1st, 2009, and (3) Support and participate in a national initiative to update the MNECB. The Committee recommended that Manitoba adopt the energy code as a regulation under The Buildings and Mobile Homes Act, rather than as a regulation under The Energy Act because The Buildings and Mobile Homes Act supersedes all other provincial legislation with respect to requirements for buildings.

Further supporting the development of energy codes for buildings, Manitoba Hydro is a former chair of the Building Energy Codes Collaborative (BECC). BECC is a federal/provincial/territorial committee supported by the Council of Energy Ministers, the Assistant Deputy Minister Steering Committee on Energy Efficiency (ASCEE) and Natural Resources Canada. It consists of representatives from both the code ministries and the energy ministries of provinces and territories working together to advance energy efficiency in building codes. In 2007, BECC was successful in securing the political and financial support necessary to convince the Canadian Commission on Building and Fire Codes to update the MNECB. In November 2011, after years of work with a nationally represented committee, the revised document entitled, *"2011 National Energy Code of Canada for Buildings"*, was published. Currently, Manitoba, Ontario, Quebec and British Columbia are recognized as the most active and have made the most progress with respect to implementing energy efficiency requirements in buildings.

4.3.2 Provincial Activities

Initially, a building code for residential homes was proposed by the Federal Government and was to be adopted by the Province of Manitoba in 1997. Due to a decline in new house starts and the perceived impact on building costs of a proposed Model National Energy Code for Houses (MNECH), it was anticipated that members of the new home construction industry would be reluctant to support the proposed MNECH. Recognizing this, Manitoba Hydro initiated and sponsored amendments to the insulation tables for new houses in the Manitoba building code as an interim measure to improve upon eroding insulation practices throughout Manitoba. The interim measures improved insulation practices in new housing north of the 53rd parallel. As anticipated, the MNECH was not adopted; however, Manitoba Hydro's amendments were introduced in Manitoba in November 1998 with the support of the new home construction industry.

In July 2006, the requirements under insulation tables for new houses in the Manitoba Building Code were simplified. Manitoba Hydro played a key role in ensuring that efficiency requirements were not significantly diluted. As a result, Manitoba's minimum requirements for insulation in new homes are the highest in Canada.

In September 2007, Manitoba Hydro presented research on the life cycle benefits of improved basement insulation to homeowners, and successfully convinced the Building Standards Board of Manitoba to request R20 in foundation walls for all homes in Manitoba.

As of January 1st, 2010, The Manitoba Energy Act regulations state that all natural gas furnaces sold in Manitoba must be at least 92% annual fuel utilization efficiency (AFUE). Meanwhile, federal regulations require a minimum efficiency of only 90%. As a result, Manitoba Hydro's Natural Gas Furnace Program has had a direct impact on market transformation in Manitoba. For this reason, the additional 2% in energy savings relative to the federal regulations have been claimed from all furnaces sold in Manitoba's residential and commercial market from January 1st, 2010 forward.

Manitoba Hydro's most recent involvement with provincial codes was with the Manitoba amendments made to Part 9 (Residential) of the Building Code that came into effect December 1st, 2010. The amendments stipulated minimum performance requirements for newly-constructed homes in the areas of insulation, windows, heating systems and plumbing fixtures. Manitoba Hydro played a key role in developing the recommendations through technical review of proposed efficiency levels, and perhaps even more critically, through preparing the industry for accepting the code recommendations by offering the Power Smart New Home Program. With the final approved efficiency levels consisting largely of the technologies which made up the Power Smart Gold standard, testament can be given to the importance of voluntary incentive-based programs in accelerating market acceptance and penetration of energy efficient technologies, thereby making the transition to building codes more seamless. With enforcement occurring for all building permits issued after December 1st, 2010, savings related to the code amendment have been realized since 2011/12.

4.3.3 Annual Energy & Demand Savings Resulting from Energy Efficiency Codes & Standards

The following section outlines the estimated energy and demand savings resulting from codes and standards improvements in the Manitoba marketplace.

Savings resulting from future codes and standards are included in targeted cost-effectiveness metrics. However, savings due to codes and standards are not included in the calculation of cost-effectiveness metrics based on actual activity (i.e. savings due to codes and standards are not included in the Power Smart Annual Review metrics).

Exhibit 4.3.3-A

Savings Resulting from Energy Efficiency Codes & Standards

CODE CATEGORY & COMPONENTS	CODE & MANITOBA HYDRO'S INFLUENCE	SAVINGS (AT METER) 2012/13		Cumulative	
Residential Insulation	-Manitoba Building Code Regulation 4/2008 (Oct. 2008) increased minimum required level of insulation from R12 to R20	3.5 1.9 339,114	GW.h MW m^3	22.5 10.4 1,403,731	GW.h MW m^3
Residential Appliances: Ranges, dishwashers, clothes washers, clothes dryers, refrigerators, freezers	-Member of Strategic Steering Committee on Performance, Energy Efficiency & Renewables (SCOPEER) -Savings based on Energy Star efficiency improvements	24.6 3.7 220,167	GW.h MW m^3	337.3 69.8 3,847,338	GW.h MW m^3
Other Residential Equipment: Central air conditioning, electric hot water tanks, furnaces, attic insulation, windows, HRVs, efficient shower heads	-CSA Standard C191-00 (July 2004) for electric hot water tanks -CSA Standard C656-05 (Nov. 2006) for central air conditioning -Mb Energy Act (Dec. 2009) states furnaces must be ≥92% AFUE (≥94% AFUE for new homes, 2010) -Manitoba Building Code Regulation 142/2010 (Dec. 2010) increased attic insulation from R40 to R50, and specified level of windows, HRVs and efficient shower heads -Manitoba Plumbing Code Regulation 32/2011 (March 2011)	22.3 7.3 2,676,690	GW.h MW m^3	52.6 14.1 7,580,523	GW.h MW m^3
Commercial Lighting: T12 lamps, LED exit signs, fluorescent ballasts	-Member of Strategic Lighting Initiative Committee (SLIC), etc. -National Energy Efficiency Act (1996): Increased min. efficiency requirement of T12 lamps from 40 to 34 watts -National Energy Efficiency Act (Nov. 2004): Min. efficiency requirements only met by LED exit signs -National Energy Efficiency Act (Nov. 2006): Increased min. efficiency requirement of fluorescent ballasts (new construction) -National Energy Efficiency Act (April 2010): Increased min. efficiency requirement of fluorescent ballasts (renovation)	15.2 4.2 -	GW.h MW m^3	122.9 34.4 -	GW.h MW m^3
Other Commercial Equipment: Furnaces	-MB Energy Act (Dec. 2009) states furnaces must be ≥92% AFUE -Text for spray valves to be added	- - 123,018	GW.h MW m^3	- - 397,578	GW.h MW m^3
Industrial Equipment: High Efficiency Motors	-Member of Coordinated Utilities Approach (CUA) -Oct. 1997 code change (min. efficiency increased to 82.5-95.0%) -Last year of claimed savings was 2006/07	- - -	GW.h MW m^3	16.2 2.8 -	GW.h MW m^3
TOTAL		65.6 17.0 3,358,989	GW.h MW m^3	551.5 131.6 13,229,170	GW.h MW m^3

In 2012/13 alone, as a result of efforts to achieve energy savings through energy efficient codes and standards, approximately 66 GW.h and 17 MW of electric savings (at meter), and 3 million cubic metres of natural gas savings were achieved. This resulted in nearly 57 thousand tonnes of greenhouse gas emission reductions. Cumulatively, it is estimated that 552 GW.h and 132 MW of electric savings (at meter), and 13 million cubic metres of natural gas savings were achieved as a result of energy efficient, resulting in 449 thousand tonnes of greenhouse gas emission reductions in 2012/13.

Exhibit 4.3.3 - B
Cumulative GW.h Savings Achieved
(at Meter)

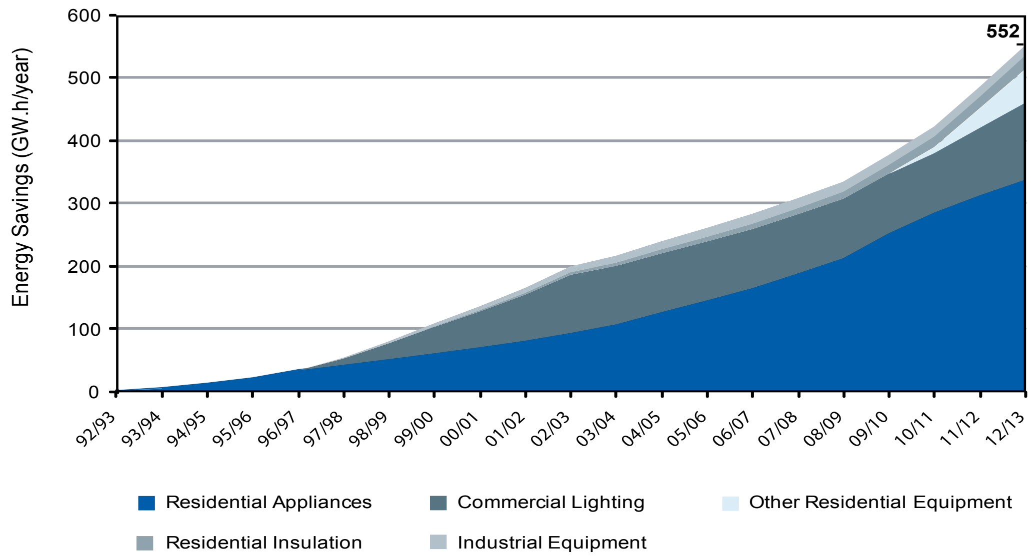


Exhibit 4.3.3- C
Cumulative MW Savings Achieved
(at Meter)

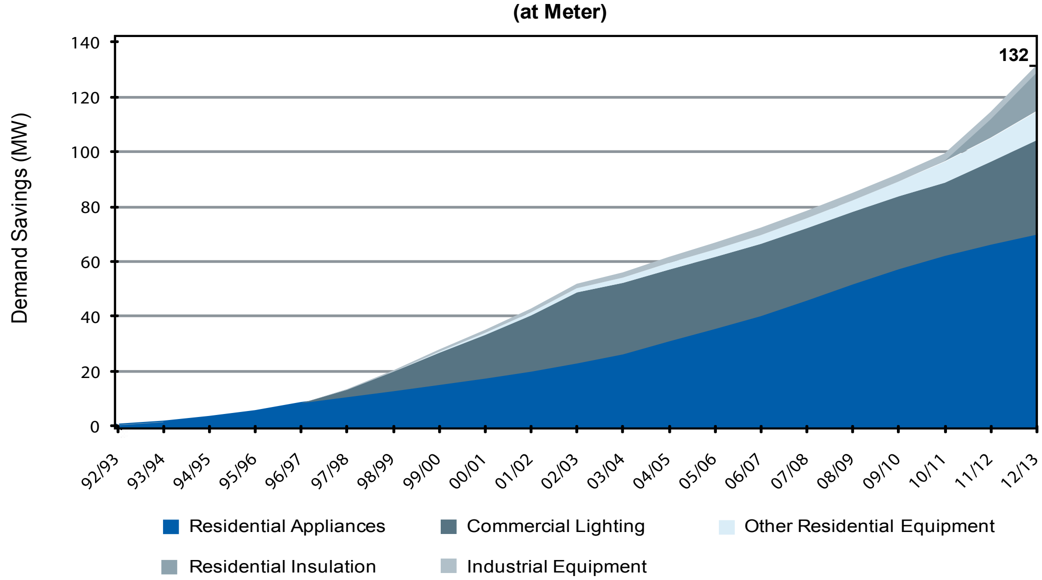
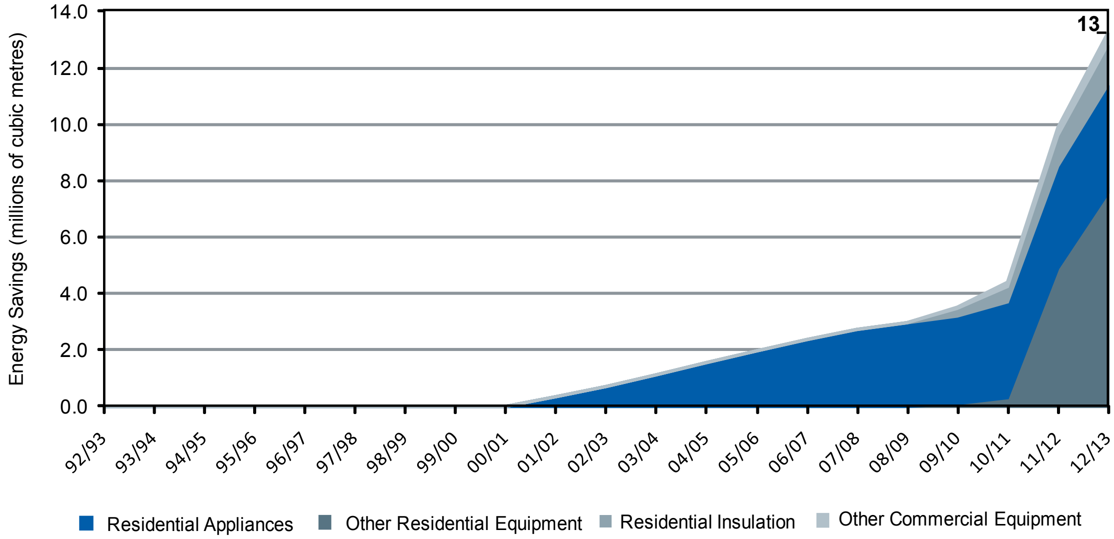


Exhibit 4.3.3 -D
Efficiency Codes & Standards
Cumulative Natural Gas Savings Achieved



Because there are many participants (utilities, governments, manufacturers, environmental groups, etc.) contributing to the formation of energy efficiency codes and standards, it is difficult to allocate specific credit for energy and demand savings among the various participants. For this reason, Manitoba Hydro only reports the estimated savings resulting from changes to energy efficiency codes and standards. In the Power Smart Annual Review, the estimated savings from codes and standards are not included in the calculation of cost effectiveness Power Smart metrics.

4.4 Incentive-Based Power Smart Programs

Power Smart incentive-based programs are designed to accelerate market awareness and acceptance of energy efficient technologies and practices.

4.4.1 Power Smart Electric Program Results

The following sections outline the Power Smart program results in terms of electric energy and demand savings and benefit/cost analyses.

4.4.1.1 Annual Energy Savings

Electric energy savings achieved by incentive-based Power Smart programs in 2012/13 is displayed by sector and program in Exhibits 4.4.1.1-A and B respectively.

Exhibit 4.4.1.1-B also provides cumulative electric energy savings achieved by incentive-based Power Smart programs.

Exhibit 4.4.1.1 - A
Percentage of Annual GW.h Savings
Electric Incentive-Based Programs

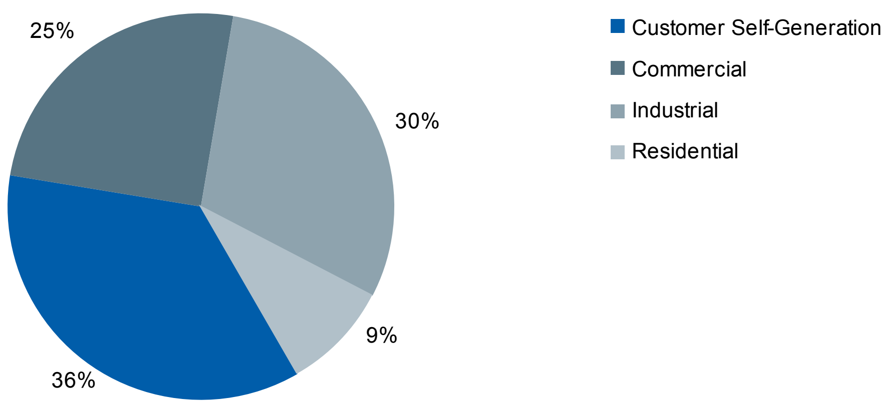


Exhibit 4.4.1.1 - B

Annual GW.h Savings - Electric Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan^
RESIDENTIAL				
Refrigerator Retirement	8.6	15.2	19.6	9.2
Home Insulation	6.2	3.4	44.9	52.6
Water & Energy Saver	3.1	2.9	12.6	19.3
Affordable Energy Program	2.8	2.5	9.3	13.7
Residential Discontinued/Completed Programs	-	-	157.2	151.9
	20.8	24.0	243.5	246.7
COMMERCIAL				
Commercial Lighting	27.8	23.2	309.0	472.7
Commercial Refrigeration	12.5	1.2	21.2	34.2
Commercial Building Envelope	5.2	4.1	29.5	50.9
Commercial New Buildings	4.1	7.0	6.4	90.4
Commercial Earth Power	2.1	1.6	29.9	52.9
Internal Retrofit	1.6	0.9	55.2	37.4
Commercial HVAC - Chillers & CO2 Sensors	1.2	1.2	9.5	16.6
Commercial Custom Measures	0.8	0.9	21.0	34.4
Commercial Clothes Washers	0.1	0.1	0.6	1.1
City of Winnipeg Power Smart Agreement	0.1	0.4	11.6	11.6
Commercial Building Optimization	0.1	1.0	1.0	20.3
Commercial Kitchen Appliances	0.0	0.1	0.7	1.3
Commercial Network Energy Management	-	1.0	0.2	0.2
Commercial Discontinued/Completed Programs	1.8	4.1	116.1	125.9
	57.6	46.8	611.9	949.8
INDUSTRIAL				
Performance Optimization	68.7	12.9	441.8	566.6
Emergency Preparedness	-	-	-	-
Industrial Discontinued/Completed Programs	-	-	54.5	54.5
	68.7	12.9	496.3	621.1
EFFICIENCY PROGRAMS SUBTOTAL	147.1	83.7	1,351.7	1,817.5
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	82.5	8.5	82.5	142.2
	82.5	8.5	82.5	142.2
TOTAL (at customer meter)	229.5	92.2	1,434.3	1,959.7
TOTAL (at generation)	255.6	104.3	1,611.9	2,203.6

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.
Free driver participation is included in the above figures.

In 2012/13 alone, Power Smart electric incentive-based programs, including both efficiency-based programs and customer self-generation, surpassed plan by 137.3 GW.h. Efficiency-based programs were 63.4 GW.h and customer self-generation was 73.9 GW.h greater than planned.

The variances within Power Smart electric incentive-based programs in 2012/13 are highlighted below:

Residential:

The residential sector, which accounted for 9% of total GW.h savings in 2012/13, contributed 20.8 GW.h, falling short of its planned savings by 3.3 GW.h.

- The Refrigerator Retirement Program achieved 8.6 GW.h of savings, below target by 6.5 GW.h or 43%. This negative variance is the result of less participation than anticipated. Targets were based on a $50 incentive, however, a $40 incentive was approved by management. The lower incentive amount likely decreased participation levels, resulting in lower overall savings.

- The Home Insulation Program saved 6.2 GW.h, 2.7 GW.h or 79% more than planned. The positive variance is the result of greater participation on the electric side of the program due to a deadline extension for ecoENERGY post-verifications. Also, the planned product mix did not include some of the higher-savings upgrades completed under the program.

Commercial:

The commercial sector, which accounted for 25% of savings in 2012/13, contributed 57.6 GW.h of savings, 10.8 GW.h more than planned.

- The Commercial Lighting Program achieved savings of 27.8 GW.h, or 20% more than anticipated despite slightly lower participation levels than planned. This is a result of differences between planned and actual product mixes and project sizes.

- The Commercial Refrigeration Program achieved savings of 12.5 GW.h, greatly exceeding planned savings of 1.2 GW.h. The positive variance was the result of an unanticipated increase in sales, largely due to a new entrant in the market.

- The Commercial New Building Program achieved savings of 4.1 GW.h, falling short of plan by 2.8 GW.h or 40%. The negative variance is mainly due to the program's assumption that buildings constructed in natural gas territory heat with natural gas. In actuality, these buildings heat with either natural gas or electricity. By using a natural gas base case, the program has over-claimed natural gas savings and under-claimed electric savings.

Industrial:

- The industrial sector account for 30% of total GW.h savings in 2012/13, with 68.7 GW.h resulting from the Performance Optimization Program. Energy savings for the Performance Optimization Program was 55.8 GW.h more than planned due to greater per project savings than anticipated. In particular, Canexus Ltd. who uses an energy-intensive process and claimed over 52 GW.h in savings.

Customer Self-Generation:

- The Bioenergy Optimization Program accounted for 36% of total GW.h savings in 2012/13. The program achieved 82.5 GW.h of savings, 73.9 GW.h above plan due to greater than expected savings resulting from Hutterite projects.

4.4.1.2 Average Winter Peak Demand Savings

Demand savings achieved by electric incentive-based Power Smart programs in 2012/13 is displayed by sector and program in Exhibits 4.4.1.2-A and B respectively. Exhibit 4.4.1.2-B also provides cumulative demand savings achieved by electric incentive-based Power Smart programs. The demand savings are presented as an average of the winter AM and PM system peak savings.

Exhibit 4.4.1.2-A
Percentage of Average Winter MW Savings
Electric Incentive-Based Programs

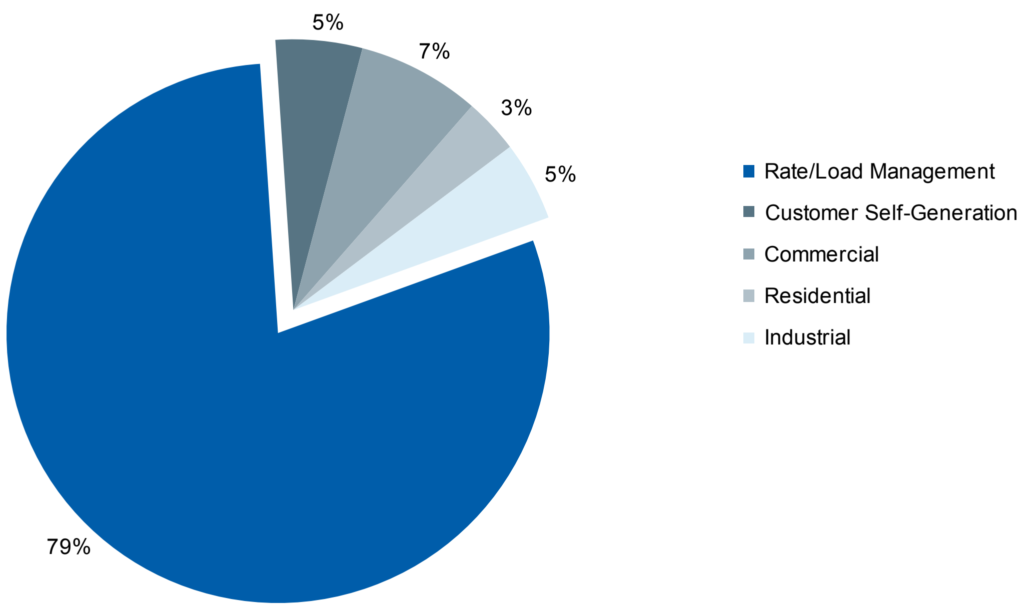


Exhibit 4.4.1.2 - B

Average Winter MW Savings - Electric Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan ^
RESIDENTIAL				
Home Insulation	3.3	1.8	22.1	26.4
Affordable Energy Program	1.1	1.0	4.1	5.6
Refrigerator Retirement	1.0	1.7	1.7	0.8
Water & Energy Saver	0.6	0.6	2.0	3.0
Residential Discontinued/Completed Programs	-	-	28.6	27.2
	6.0	5.1	58.4	62.9
COMMERCIAL				
Commercial Lighting	7.7	6.4	56.5	103.2
Commercial Building Envelope	2.0	1.6	13.1	21.4
Commercial Refrigeration	1.4	0.1	3.5	5.0
New Buildings Program	1.1	1.8	1.5	23.8
Commercial Earth Power	0.5	0.4	12.4	17.9
Internal Retrofit	0.2	0.1	11.9	8.4
Commercial Clothes Washers	0.1	0.1	0.4	0.7
City of Winnipeg Power Smart Agreement	0.0	0.1	2.6	2.6
Commercial HVAC - Chillers & CO2 Sensors	0.0	0.1	0.0	0.5
Commercial Building Optimization	0.0	0.2	0.0	3.9
Commercial Kitchen Appliances	0.0	0.0	0.2	0.4
Commercial Network Energy Management	0.0	0.4	0.0	0.0
Commercial Custom Measures	-	0.2	1.7	5.4
Commercial Discontinued/Completed Programs	0.2	0.2	15.4	16.0
	13.3	11.8	119.3	209.3
INDUSTRIAL				
Performance Optimization	8.6	2.0	87.6	109.1
Emergency Preparedness	-	-	-	-
Industrial Discontinued/Completed Programs	-	-	8.2	8.2
	8.6	2.0	95.7	117.3
EFFICIENCY PROGRAMS SUBTOTAL	28.0	18.9	273.4	389.5
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	9.4	1.0	9.4	22.5
	9.4	1.0	9.4	22.5
RATE/LOAD MANAGEMENT PROGRAMS				
Curtailable Rates	144.8	146.4	144.8	295.0
	144.8	146.4	144.8	295.0
TOTAL (at customer meter)	182.1	166.3	427.6	707.0
TOTAL (at generation)	201.1	183.6	477.5	788.6

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.
Free driver participation is included in the above figures.

In 2012/13 alone, Power Smart electric incentive-based programs, including both efficiency-based and customer self-generation programs, exceeded plan by 15.8 MW. By far, the greatest contributor of demand savings was the Curtailable Rates Program, which accounted for 79% of total MW savings.

The variances within Power Smart electric incentive-based programs in 2012/13 are highlighted below:

Residential:

The residential sector, which accounted for 3% of total demand savings in 2012/13, contributed 6.0 MW, exceeding its planned savings by 0.9 MW.

- The Home Insulation Program exceeded planned demand savings by 1.5 MW or 79%. The positive variance is the result of greater participation than anticipated, due to a deadline extension for ecoENERGY post-verification. Also, the planned product mix did not include some of the higher-savings upgrades completed under the program.
- The Refrigerator Retirement Program fell short of planned savings by 0.7 MW or 43%. This negative variance is the result of less participation than anticipated. Planned participation targets were based on a $50 incentive; however, the approved program offered a $40 incentive. The lower incentive amount likely led to decreased participation levels which resulted in lower overall demand savings.

Commercial:

The commercial sector, which accounted for 7% of total demand savings in 2012/13, contributed 13.3 MW of savings, 1.5 MW above target.

- The Commercial Lighting Program achieved 7.7 MW of demand savings, exceeding its planned demand savings of 6.4 MW despite slightly lower participation than anticipated. This is a result of differences between planned and actual product mixes and project sizes.
- The Commercial Refrigeration Program achieved savings of 1.4 MW, exceeding targets by 1.3 MW. The positive variance was the result of an unanticipated increase in sales, largely due to a new entrant in the market.

Industrial:

- The industrial sector accounted for 5% of total demand savings in 2012/13, with 8.6 MW resulting from the Performance Optimization Program. Demand savings for the Performance Optimization Program were 6.6 MW greater than planned due to greater per project savings than anticipated, largely due to Canexus Ltd.

Customer Self-Generation:

- The Bioenergy Optimization Program contributed 9.4 MW in total demand savings, surpassing plan by 8.4 MW. Due to higher than anticipated savings resulting from Hutterite projects, demand savings were greater than planned.

Rate/Load Management:

- The Curtailable Rates Program, which accounted for 79% of total demand savings in 2012/13, contributed 144.8 MW of savings, 1.7 MW less than planned. For further details, please see APPENDIX E - "Curtailable Rates Program Information & Methodology".

4.4.1.3 Electric Total Resource Cost - Benefit/Cost Analysis

Exhibits 4.4.1.3-A and B show the electric benefit/cost analysis results under the total resource cost (TRC) metric by program. The calculation of the benefit/cost ratio was based on a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness.

Exhibit 4.4.1.3-A
2012/13 TRC- Electric Incentive-Based Programs

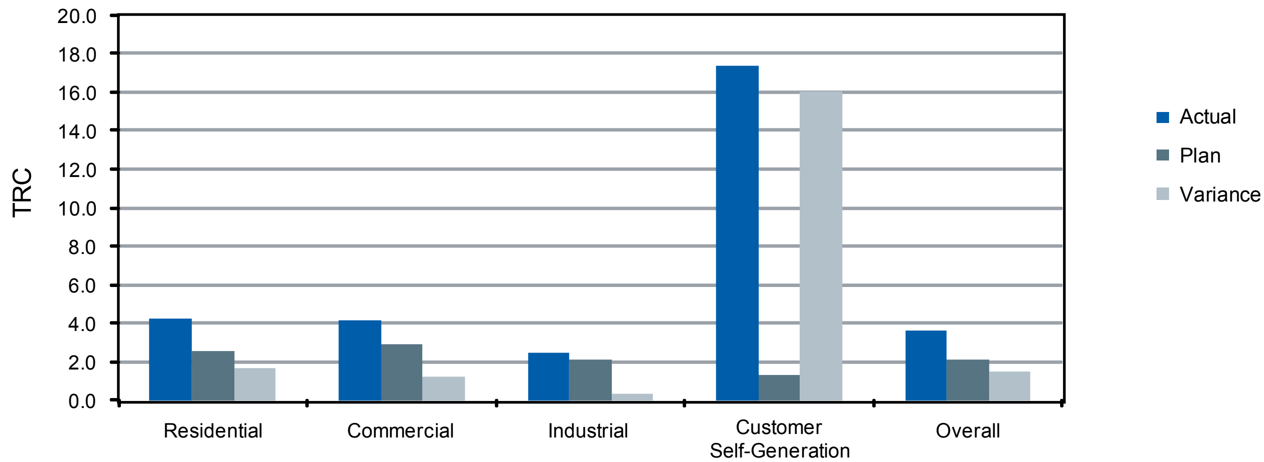


Exhibit 4.4.1.3 - B

Total Resource Cost Benefit/Cost Analysis - Electric Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^^	Total**	2026/27 Plan^^
		TRC		
RESIDENTIAL				
Water & Energy Saver †	18.1	4.8	18.8	4.6
Home Insulation	6.2	4.7	5.0	5.1
Affordable Energy Program* †	2.5	1.5	1.7	1.6
Refrigerator Retirement	1.5	1.8	2.1	1.9
	4.2	2.5	4.2	2.9
COMMERCIAL				
Commercial New Buildings	21.4	4.7	6.8	8.1
Commercial Building Envelope	5.9	4.7	4.9	4.0
City of Winnipeg Power Smart AgreementØ	5.8	10.3	1.2	10.3
Commercial Refrigeration	5.4	1.8	4.0	2.6
Commercial Lighting	3.7	2.5	2.6	2.6
Commercial Kitchen Appliances †	3.1	13.4	4.7	20.7
Commercial Earth Power	3.0	1.7	2.0	1.7
Commercial HVAC	3.0	3.8	2.0	4.5
Internal Retrofit	2.1	1.7	2.0	1.6
Commercial Clothes Washers †	1.1	1.8	1.4	3.7
Commercial Custom Measures	1.0	1.8	1.7	2.0
Commercial Building Optimization	0.5	3.7	0.6	5.1
Commercial Network Energy Management	-	1.6	0.2	2.0
	4.1	2.9	2.5	3.2
INDUSTRIAL				
Performance Optimization	2.5	2.1	3.3	2.7
	2.5	2.1	3.3	2.7
DISCONTINUED/COMPLETED PROGRAMS †	18.7	5.4	2.8	8.8
	18.7	5.4	2.8	8.8
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	17.4	1.3	2.2	1.6
	17.4	1.3	2.2	1.6
OVERALL: PROGRAM COSTS	4.0	2.5	2.8	2.9
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	3.6	2.1	2.4	2.3

* Includes all Affordable Energy Fund expenditures and external funding.
** "Total" values represent the results of the program/portfolio since its inception.
Ø Includes the present value of projected future commitment payment receipts.
† Includes water savings benefits.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Free driver participation is included in the above figures.

4.4.1.4 Electric Rate Impact Measure- Benefit/Cost Analysis

Exhibits 4.4.1.4-A and B identify the electric benefit/cost ratios under the rate impact measure (RIM) metric by program. The calculation of the benefit/cost ratio is based on a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness.

Exhibit 4.4.1.4 - A
2012/13 RIM - Electric Incentive-Based Programs

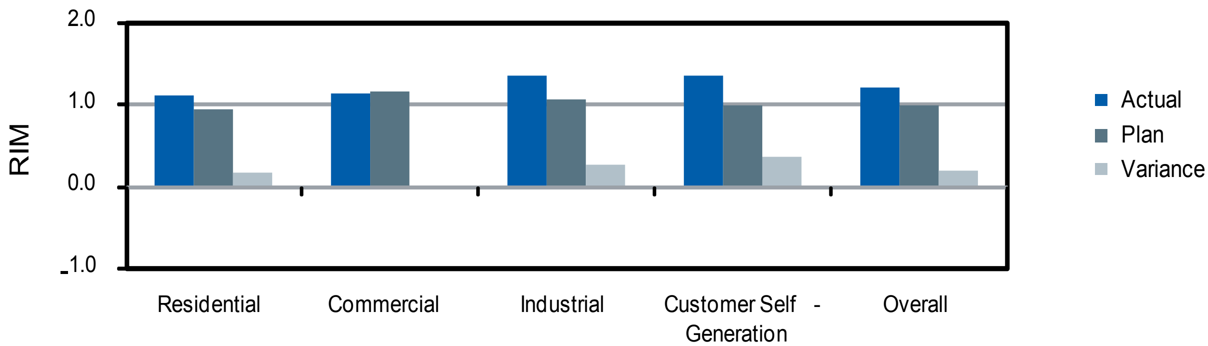


Exhibit 4.4.1.4 - B

Rate Impact Cost Benefit/Cost Analysis - Electric Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^^	Total*	2026/27 Plan^^
		RIM		
RESIDENTIAL				
Home Insulation	1.5	1.4	1.6	1.5
Affordable Energy Program**	1.1	1.0	0.9	1.1
Water & Energy Saver	0.9	0.8	1.0	0.9
Refrigerator Retirement	0.7	0.7	0.7	0.7
	1.1	0.9	1.3	1.1
COMMERCIAL				
Internal Retrofit	2.1	1.7	2.0	1.6
Commercial New Buildings	1.8	1.6	1.5	1.7
Commercial Earth Power	1.4	1.3	1.7	1.3
Commercial Building Envelope	1.4	1.4	1.5	1.3
Commercial Refrigeration	1.2	0.9	1.2	1.1
Commercial Custom Measures	1.1	1.3	1.3	1.4
City of Winnipeg Power Smart AgreementØ	1.0	1.2	0.7	1.2
Commercial Lighting	1.0	1.0	1.1	1.0
Commercial Clothes Washers	1.0	0.9	1.1	1.3
Commercial HVAC	0.9	0.9	1.0	0.9
Commercial Kitchen Appliances	0.7	0.9	1.0	1.6
Commercial Building Optimization	0.4	1.1	0.5	1.3
Commercial Network Energy Management	-	0.9	0.2	1.2
	1.1	1.2	1.2	1.2
INDUSTRIAL				
Performance Optimization	1.4	1.1	1.3	1.3
	1.4	1.1	1.3	1.3
DISCONTINUED/COMPLETED PROGRAMS	1.3	1.2	0.9	1.3
	1.3	1.2	0.9	1.3
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	1.4	1.0	1.3	1.2
	1.4	1.0	1.3	1.2
OVERALL PROGRAM COSTS	1.3	1.1	1.2	1.2
OVERALL PROGRAM COSTS + SUPPORT COSTS^	1.2	1.0	1.1	1.1

* "Total" values represent the results of the program/portfolio since its inception.
** Includes all Affordable Energy Fund expenditures, excluding external funding.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Ø Includes the present value of projected future commitment payment receipts.
Note: Benefit/Cost analysis is not calculated for rate/load management programs.
Free driver participation is included in the above figures.

4.4.1.5 Electric Average Levelized Utility Cost - ¢/kW.h Saved

Exhibits 4.4.1.5-A and B highlight the average levelized utility cost of 2012/13 electric incentive-based programs in ¢/kW.h saved. The calculation of ¢/kW.h saved is based upon current program kW.h savings at generation over a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness. The utility costs presented do not include costs associated with DSM support programs, standards activities or the customer costs of DSM measures.

Exhibit 4.4.1.5-A
2012/13 Average Levelized Utility Cost
Electric Incentive-Based Programs
at generation

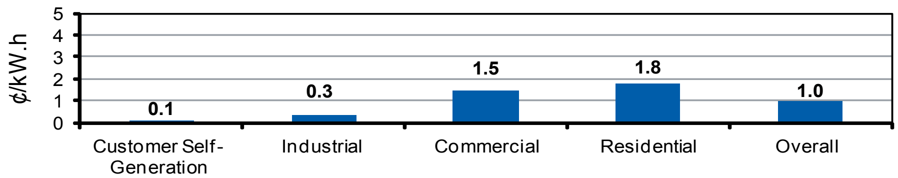


Exhibit 4.4.1.5 - B

Average Levelized Utility Cost at Generation - ¢/kW.h Saved by Power Smart Programs

	2012/13 Actual	2012/13 Total**	2026/27 Plan^^
		LUC (¢/kW.h)	
RESIDENTIAL			
Affordable Energy Program*	2.8	4.8	3.4
Refrigerator Retirement	2.0	1.6	1.6
Water & Energy Saver	1.5	1.1	2.4
Home Insulation	1.3	2.3	1.9
Discontinued/Completed Programs	8.6	1.4	-
	1.8	1.7	2.1
COMMERCIAL			
Commercial Building Optimization	10.8	5.4	1.1
Commercial Kitchen Appliances	5.3	3.6	1.3
Commercial Clothes Washer	4.3	7.6	1.6
Internal Retrofit	3.2	3.7	4.1
Commercial Lighting	2.3	1.6	2.5
City of Winnipeg Power Smart Agreement	2.0	8.4	0.7
Commercial Building Envelope	1.8	2.1	2.3
Commercial Earth Power	0.9	1.3	1.5
Commercial HVAC	0.8	1.4	1.1
Commercial Custom Measures	0.5	0.9	2.0
Commercial Refrigeration	0.4	1.0	1.5
Commercial New Buildings	0.2	1.2	0.5
Discontinued/Completed Programs	0.0	1.0	1.5
Commercial Network Energy Management	-	23.8	1.5
	1.5	1.8	1.7
INDUSTRIAL			
Performance Optimization	0.3	0.4	1.5
Discontinued/Completed Programs	-	1.3	-
	0.3	0.7	1.5
CUSTOMER SELF-GENERATION PROGRAMS			
Bioenergy Optimization	0.1	1.0	1.6
	0.1	1.0	1.6
OVERALL: PROGRAM COSTS	0.8	1.2	1.7
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	1.0	1.7	2.4

* Includes all Affordable Energy Fund expenditures, excluding external funding.
** "Total" values represent the results of the program/portfolio since its inception.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Average levelized utility cost analysis is not provided for rate/load management programs.
Free driver participation is included in the above figures.

4.4.1.6 Electric Levelized Resource Cost- ¢/kW.h Saved

Exhibits 4.4.1.6-A and B highlight the average levelized resource cost of 2012/13 electric incentive-based programs in ¢/kW.h saved. The calculation of ¢/kW.h saved is based upon current program kW.h savings at generation over a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness. The resource costs presented do not include costs associated with DSM support programs or standards activities, however they do include DSM measures.

Exhibit 4.4.1.6-A
2012/13 Average Levelized Resource Cost
at generation

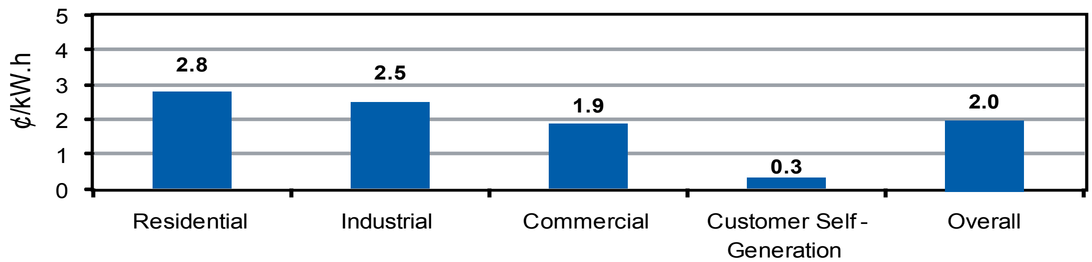


Exhibit 4.4.1.6 - B

Average Levelized Resource Cost at Generation - ¢/kW.h Saved by Power Smart Programs

	2012/13 Actual	2012/13 Total**	2026/27 Plan^^
		LRC(¢/kW.h)	
RESIDENTIAL			
Affordable Energy Program*	4.3	8.5	6.9
Refrigerator Retirement	3.7	2.8	3.1
Home Insulation	2.0	2.9	2.6
Water & Energy Saver	1.4	1.1	2.3
	2.8	3.2	3.4
COMMERCIAL			
Commercial Clothes Washers	20.7	23.7	4.5
Commercial Building Optimization	12.2	9.4	1.7
Commercial Kitchen Appliances	9.0	4.5	1.9
Commercial Custom Measures	5.4	3.4	4.9
Internal Retrofit	3.2	3.7	4.1
Commercial Earth Power	2.8	5.6	5.5
Commercial Lighting	2.3	2.5	3.6
Commercial Building Envelope	1.7	2.9	2.8
City of Winnipeg Power Smart Agreement	1.5	8.4	0.8
Commercial HVAC	1.4	2.6	1.4
Commercial Refrigeration	1.1	2.0	2.8
Commercial New Buildings	0.4	1.4	1.2
Commercial Network Energy Management	0.0	23.7	4.7
	1.9	3.0	3.0
INDUSTRIAL			
Performance Optimization	2.5	1.8	3.0
	2.5	1.8	3.0
CUSTOMER SELF-GENERATION PROGRAMS			
Bioenergy Optimization	0.3	3.1	4.2
	0.3	3.1	4.2
DISCONTINUED/COMPLETED PROGRAMS	0.3	2.2	0.7
OVERALL: PROGRAM COSTS	1.8	2.4	3.1
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	2.0	2.9	3.8

* Includes all Affordable Energy Fund expenditures, excluding external funding.
** "Total" values represent the results of the program/portfolio since its inception.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Average levelized resource cost analysis is not provided for rate/load management programs.
Free driver participation is included in the above figures.

4.4.2 Power Smart Natural Gas Program Results

The following sections outline the Power Smart program results in terms of natural gas energy savings, and benefit/cost analyses.

4.4.2.1 Annual Natural Gas Energy Savings

Natural gas energy savings achieved by incentive-based Power Smart programs in 2012/13 is displayed by sector and program in Exhibits 4.4.2.1-A and B respectively.

Exhibit 4.4.2.1-B also provides cumulative natural gas energy savings achieved by incentive-based Power Smart programs.

Exhibit 4.4.2.1-A
Percentage of Annual Natural Gas Savings
Incentive Based Programs

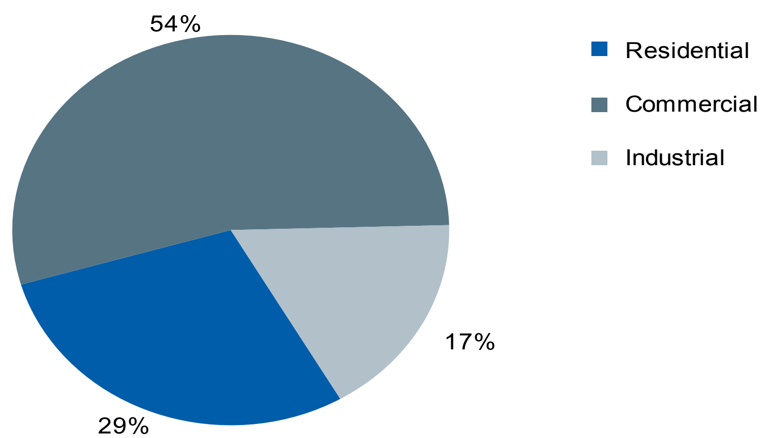


Exhibit 4.4.2.1 - B
Annual Natural Gas Savings - Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^	Total*	2026/27 Plan^
		millions of cubic metres		
RESIDENTIAL				
Affordable Energy Program	1.1	1.2	4.6	6.4
Home Insulation	1.1	1.0	11.3	15.0
Water & Energy Saver	1.0	0.8	2.8	4.3
Residential Discontinued/Completed Programs	0.0	0.0	7.7	7.7
	3.3	3.0	26.4	33.5
COMMERCIAL				
Commercial New Buildings	2.4	0.5	2.8	6.5
Commercial HVAC	1.3	1.0	8.4	12.7
Commercial Building Envelope	1.2	1.4	9.4	16.7
Commercial Custom Measures	1.1	0.1	1.4	2.3
Commercial Building Optimization	0.1	0.3	0.4	5.6
Commercial Kitchen Appliances	0.0	0.0	0.1	0.2
City of Winnipeg Power Smart Agreement	-	0.0	0.8	0.8
Commercial Discontinued/Completed Programs	-	0.0	0.0	2.4
	6.1	3.3	23.4	47.4
INDUSTRIAL				
Natural Gas Optimization	1.9	1.6	12.5	18.5
Industrial Discontinued/Completed	-	-	-	-
	1.9	1.6	12.5	18.5
EFFICIENCY PROGRAMS SUBTOTAL	11.3	7.9	62.2	99.4
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	-	0.0	-	1.5
	-	0.0	-	1.5
INTERACTIVE EFFECTS SUBTOTAL	(0.7)	(1.1)	(12.0)	(10.4)
NET IMPACT OVERALL	10.6	6.9	50.1	90.5

^ Plan estimates are from the 2012 Base DSM Forecast.
* Savings include actual + persisting results, up to and including 2012/13.
Note: Figures may not add due to rounding.
Free driver participation is included in the above figures.

In 2012/13 alone, Power Smart natural gas incentive-based programs, including both efficiency-based and customer self-generation programs, surpassed plan by 3.7 million cubic metres.

The variances within Power Smart natural gas incentive-based programs in 2012/13 are highlighted below:

Residential:

The residential sector, which contributed 3.3 million cubic metres in savings, accounted for 29% of total savings in 2012/13, surpassing planned savings by 0.2 million cubic metres.

- The Water & Energy Saver Program achieved 1.0 million cubic metres in savings, surpassing plan by 22%. The positive variance is due to more gas participants than anticipated and a slight increase in per unit energy savings.

Commercial:

The commercial sector, contributed 6.1 million cubic metres of savings. It accounted for 54% of total savings in 2012/13, surpassing planned savings by 2.8 million cubic metres.

- The Commercial New Buildings Program achieved savings of 2.4 million cubic metres, surpassing plan by 2.0 million cubic metres. The variance is mainly due to the program's assumption that buildings constructed in natural gas territory heat with natural gas. In actuality, these buildings heat with either natural gas or electricity. By using a natural gas base case, the program has over-claimed natural gas savings and under-claimed electric savings.
- The Commercial Custom Measures Program achieved 1.1 million cubic metres in savings, surpassing plan by 1.0 million cubic metres. This was primarily due to more projects with natural gas savings than planned. In addition, one project accounted for approximately 25% of the natural gas savings.

Industrial:

- The Natural Gas Optimization Program contributed 1.9 million cubic metres of natural gas savings, 21% more than planned. This positive variance can be attributed to greater than anticipated per project savings.

Customer Self-Generation:

- Although natural gas savings were planned for, none were realized by the Bioenergy Optimization Program in 2012/13.

Some electric Power Smart programs result in an increase or decrease in natural gas consumption, referred to as interactive effects. For example, a more energy efficient lighting system emits less heat, requiring more energy to heat the space. In cases where the heat is produced through electric heating sources, interactive effects are taken into account when calculating the anticipated electricity savings that will result from the program. In cases where the heat is produced through natural gas heating systems, the interactive effects are taken into account when determining the natural gas savings. These interactive effects represent the increase in natural gas consumption in natural gas-heated homes resulting from the installation of energy efficient lighting systems.

In 2012/13, interactive effects increased consumption by 0.7 million cubic metres, reducing incentive-based natural gas savings to 10.6 million cubic metres. Interactive effects were lower than planned by 0.4 million cubic metres.

4.4.2.2 Natural Gas Total Resource Cost - Benefit/Cost Analysis

Exhibits 4.4.2.2-A and B show the natural gas benefit/cost analysis results under the total resource cost (TRC) metric by program. The calculation of the benefit/cost ratio was based on a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios Used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness.

Exhibit 4.4.2.2-A
2012/13 TRC - Natural Gas Incentive-Based Programs

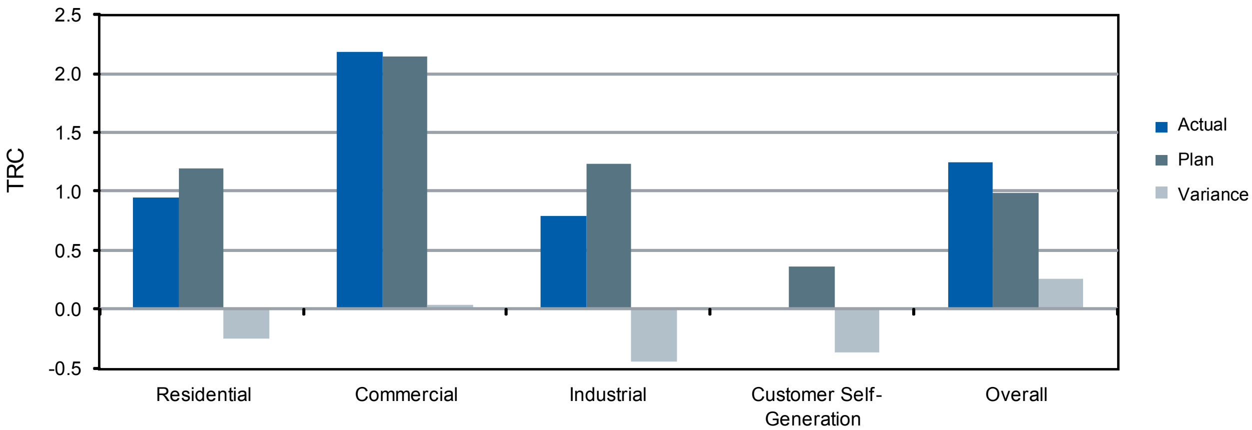


Exhibit 4.4.2.2 - B

Total Resource Cost Benefit/Cost Analysis - Natural Gas Incentive-Based Program

	2012/13 Actual	2012/13 Plan^^	Total**	2026/27 Plan^^
		TRC		
RESIDENTIAL				
Water & Energy Saver †	2.7	4.4	3.3	5.5
Home Insulation	1.4	1.4	1.7	1.5
Affordable Energy Program* †	0.0	0.5	0.0	0.6
	1.0	1.2	1.3	1.2
COMMERCIAL				
Commercial New Buildings	4.1	1.7	3.6	3.1
Commercial HVAC	2.0	2.5	3.1	2.2
Commercial Building Envelope	1.6	1.9	2.4	2.0
Commercial Building Optimization	1.5	1.3	0.9	1.7
Commercial Custom Measures	1.3	1.3	1.3	1.4
Commercial Kitchen Appliances †	0.7	23.1	1.4	7.8
	2.2	2.1	2.7	2.2
INDUSTRIAL				
Industrial Natural Gas Optimization	0.8	1.2	1.9	1.3
	0.8	1.2	1.9	1.3
DISCONTINUED/COMPLETED PROGRAMS †	-	124.8	1.5	125.7
	-	124.8	1.5	125.7
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	-	0.4	-	2.0
	-	0.4	-	2.0
OVERALL: PROGRAM COSTS	1.3	1.4	1.6	1.5
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	1.2	1.0	1.4	1.1

* Includes all AEF & FRP expenditures and external funding.
** "Total" values represent the results of the program/portfolio since its inception.
† Includes water savings benefits.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Increased or decreased natural gas benefits resulting from electric incentive-based programs have been included in the overall calculation. Free driver participation is included in the above figures.

4.4.2.3 Natural Gas Rate Impact Measure - Benefit/Cost Analysis

Exhibits 4.4.2.3-A and B identify the benefit/cost ratios under the rate impact measure (RIM) metric. The calculation of the benefit/cost ratio is based on a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios Used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness.

Exhibit 4.4.2.3-A
2012/13 RIM - Natural Gas Incentive-Based Programs

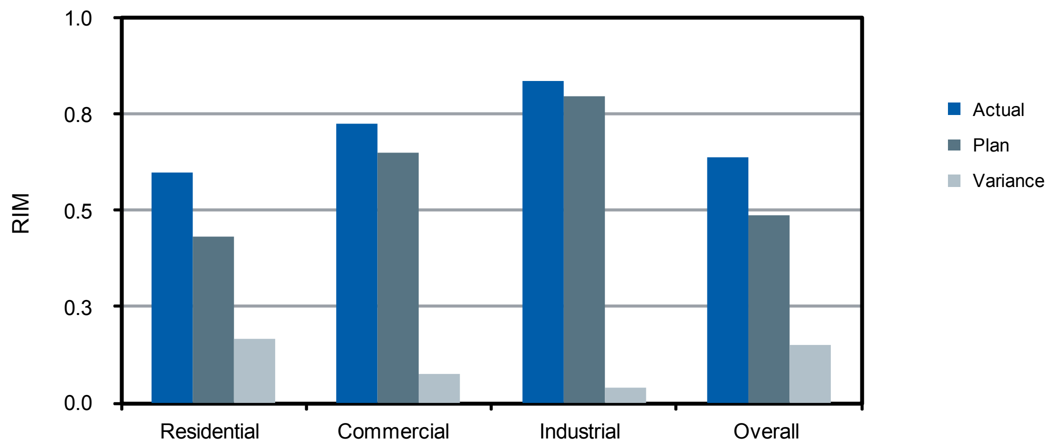


Exhibit 4.4.2.3 - B

Rate Impact Cost Benefit/Cost Analysis - Natural Gas Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^^	Total*	2026/27 Plan^^
		RIM		
RESIDENTIAL				
Water & Energy Saver	0.6	0.5	0.7	0.6
Home Insulation	0.6	0.6	0.7	0.6
Affordable Energy Program**	0.3	0.3	0.4	0.3
	0.6	0.4	0.7	0.5
COMMERCIAL				
Commercial New Buildings	0.8	0.7	0.8	0.7
Commercial Custom Measures	0.8	0.7	0.8	0.7
Commercial HVAC	0.7	0.7	0.8	0.8
Commercial Building Envelope	0.6	0.6	0.7	0.6
Commercial Building Optimization	0.6	0.6	0.4	0.6
Commercial Kitchen Appliances	0.3	0.4	0.5	0.7
Internal Retrofit	-	2.1	-	2.1
City of Winnipeg Power Smart Agreement†	-	-	1.0	-
	0.7	0.6	0.7	0.7
INDUSTRIAL				
Natural Gas Optimization	0.8	0.8	0.9	0.8
	0.8	0.8	0.9	0.8
DISCONTINUED/COMPLETED PROGRAMS	-	0.8	0.7	0.8
	-	0.8	0.7	0.8
CUSTOMER SELF-GENERATION				
Bioenergy Optimization	-	0.3	-	0.8
	-	0.3	-	0.8
OVERALL: PROGRAM COSTS	1.2	0.6	1.3	0.6
OVERALL: PROGRAM COSTS incl. INTERACTIVE EFFECTS	0.7	0.6	0.7	0.6
OVERALL: PROGRAM COSTS + SUPPORT COSTS incl. INTERACTIVE EFFECTS^	0.6	0.5	0.7	0.5

^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
* "Total" values represent the results of the program/portfolio since its inception.
** Includes all apportioned Affordable Energy Fund and Furnace Replacement Program expenditures, excluding external funding. AEP's 'Actual' RIM, including apportioned Affordable Energy Fund without the Furnace Replacement Program was 0.36. AEP's "Actual' RIM, with the Furnace Replacement Program only was 0.18.
† Includes only natural gas bill reduction costs. All other costs were accounted for within electric cost elements.
Note: Free driver participation is included in the above figures.

4.4.2.4 Natural Gas Average Levelized Utility Cost - ¢/m³ Saved

Exhibits 4.4.2.4-A and B highlight the average levelized utility cost of 2012/13 natural gas incentive-based programs in ¢/m³ saved. The calculation of ¢/m³ saved is based upon current program natural gas savings over a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness. The utility costs presented do not include costs associated with future Power Smart incentive-based programs, DSM support programs, standards activities or the customer costs of DSM measures.

Exhibit 4.4.2.4-A
2012/13 Average Levelized Utility Cost (¢/m³)
Natural Gas Incentive-Based Programs

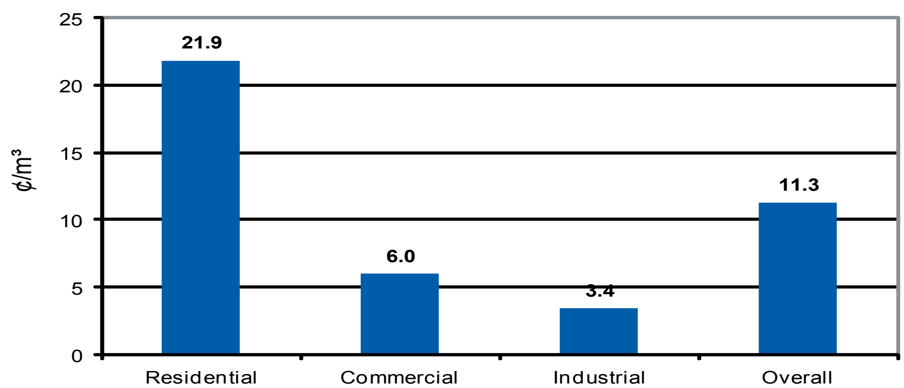


Exhibit 4.4.2.4 - B

Average Levelized Utility Cost - ¢/m³ Saved by Power Smart Programs

	2012/13 Actual	2012/13 Total**	2026/27 Plan^^
		LUC(¢/m³)	
RESIDENTIAL			
Affordable Energy Program*	52.1	43.4	54.0
Water & Energy Saver	10.7	10.0	10.1
Home Insulation	8.9	10.5	10.6
	21.9	16.4	23.7
COMMERCIAL			
Commercial Kitchen Appliances	42.9	24.8	6.5
Commercial Building Optimization	16.2	42.1	11.2
Commercial Building Envelope	12.0	10.7	11.8
Commercial HVAC	7.9	6.5	4.9
Commercial Custom Measures	3.5	5.7	9.1
Commercial New Buildings	3.1	4.6	5.4
Internal Retrofit Program	-	-	12.7
	6.0	8.0	8.5
INDUSTRIAL			
Natural Gas Optimization	3.4	2.6	5.1
	3.4	2.6	5.1
CUSTOMER SELF-GENERATION PROGRAMS			
Bioenergy Optimization	-	-	4.8
DISCONTINUED/COMPLETED PROGRAMS	-	9.1	0.7
OVERALL: PROGRAM COSTS	9.7	9.7	12.6
OVERALL: PROGRAM COSTS incl. INTERACTIVE EFFECTS†	10.2	10.9	13.2
OVERALL: PROGRAM COSTS + SUPPORT COSTS incl. INTERACTIVE EFFECTS^	11.3	13.7	22.1

* Includes all apportioned Affordable Energy Fund and Furnace Replacement Program expenditures, excluding external funding. AEP's 'Actual' levelized utility cost, including apportioned Affordable Energy Fund, without the Furnace Replacement Program was 39.1 ¢/m³. AEP's 'Actual' levelized utility cost with the Furnace Replacement Program only was 104.9 ¢/m³.

** "Total" values represent the results of the program/portfolio since its inception.

^ Support costs contain DSM support programs, basic information services and program support costs.

^^ Plan estimates are from the 2012 Base DSM Forecast.

† Increased or decreased natural gas benefits resulting from electric incentive-based programs have been included in the overall calculation.

Note: Free driver participation is included in the above figures.

4.4.2.5 Natural Gas Levelized Resource Cost- ¢/m³ Saved

Exhibits 4.4.2.5-A and B highlight the average levelized resource cost of 2012/13 natural gas incentive-based programs in ¢/m³. The calculation of ¢/m³ saved was based upon current program natural gas savings over a 30-year evaluation period. Refer to APPENDIX B - 'Explanation of Benefit/Cost Ratios used in DSM Economic Metrics' for formulas and criteria used to determine cost-effectiveness. The resource costs presented do not include costs associated with future Power Smart incentive-based programs, DSM support programs or standards activities, however they do include the customer costs of DSM measures.

Exhibit 4.4.2.5-A
2012/13 Levelized Resource Cost (¢/m³)

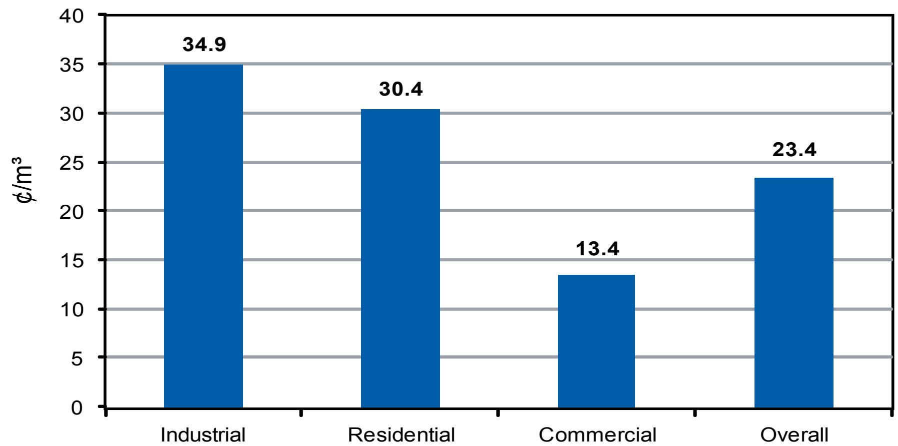


Exhibit 4.4.2.5 - B

Natural Gas Levelized Resource Cost - ¢/m³ Saved by Power Smart Programs

	2012/13 Actual	2012/13 Total**	2026/27 Plan^^
		LRC (¢/m³)	
RESIDENTIAL			
Affordable Energy Program*	63.5	56.0	54.8
Home Insulation	20.7	20.1	20.2
Water & Energy Saver	10.6	10.0	9.7
	30.4	25.5	29.2
COMMERCIAL			
Commercial Kitchen Appliances	40.4	25.1	11.1
Commercial Custom Measures	21.7	23.5	22.0
Commercial Building Optimization	18.4	41.7	18.2
Commercial Building Envelope	17.6	14.5	15.4
Commercial HVAC	14.6	10.9	14.0
Commercial New Buildings	7.2	8.5	10.0
Internal Retrofit Program	-	-	12.7
	13.4	12.5	14.4
INDUSTRIAL			
Natural Gas Optimization	34.9	17.1	22.1
	34.9	17.1	22.1
CUSTOMER SELF-GENERATION PROGRAMS			
Bioenergy Optimization	-	-	14.4
	-	-	14.4
DISCONTINUED/COMPLETED PROGRAMS	-	22.4	0.7
OVERALL: PROGRAM COSTS	21.3	18.6	20.0
OVERALL: PROGRAM COSTS incl. INTERACTIVE EFFECTS†	22.3	20.9	21.0
OVERALL: PROGRAM COSTS + SUPPORT COSTS incl. INTERACTIVE EFFECTS^	23.4	23.7	29.9

* Includes all Affordable Energy Fund & Furnace Replacement Program expenditures, excluding external funding.
** "Total" values represent the results of the program/portfolio since its inception.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Average levelized resource cost analysis is not provided for rate/load management programs.
Free driver participation is included in the above figures.

4.4.3 Power Smart Combined Electric & Natural Gas Program Results

Total Resource Cost - Benefit/Cost Analysis

Exhibits 4.4.3-A and B show the combined electricity and natural gas benefit/cost analysis results under the total resource cost (TRC) metric by program. The calculation of the benefit/cost ratio was based on a 30-year evaluation period.

Exhibit 4.4.3-A
2012/13 TRC - Combined Electric & Gas Incentive-Based Programs

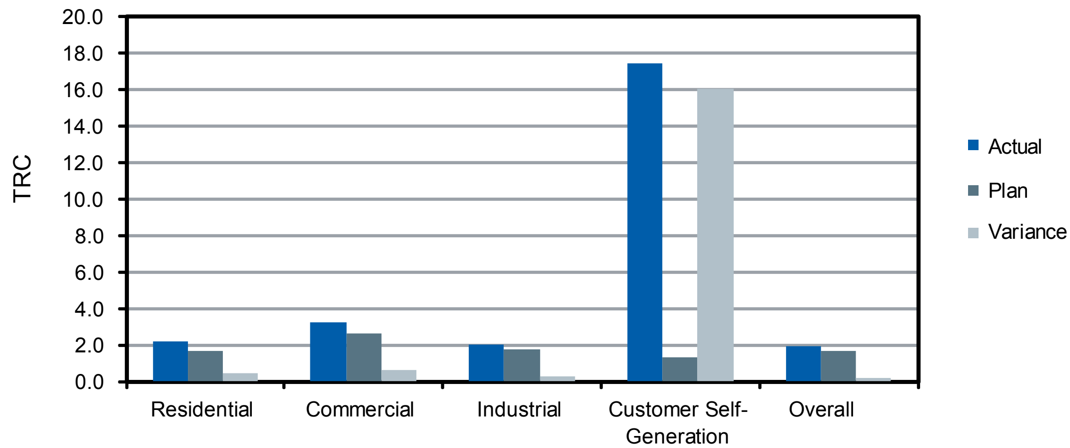


Exhibit 4.4.3 - B

Total Resource Cost Benefit Analysis - Combined Electric & Natural Gas Incentive-Based Programs

	2012/13 Actual	2012/13 Plan^^	Total**	2026/27 Plan^^
			TRC	
RESIDENTIAL				
Water & Energy Saver†	7.8	4.6	8.9	5.0
Home Insulation	3.2	2.6	2.9	2.5
Refrigerator Retirement	1.1	1.3	1.4	1.4
Affordable Energy Program*†	0.9	0.8	0.9	0.8
	2.2	1.7	2.2	1.7
COMMERCIAL				
Commercial New Buildings	5.8	3.6	4.6	6.4
City of Winnipeg Power Smart Agreement Ø	5.8	10.3	1.5	10.3
Commercial Refrigeration	5.5	2.0	4.3	2.8
Commercial Lighting	3.6	2.4	2.5	2.5
Commercial Earth Power	3.0	1.7	2.0	1.7
Commercial Building Envelope	3.0	2.8	3.4	2.7
Commercial HVAC	2.2	2.7	3.0	2.6
Internal Retrofit	2.1	1.8	2.0	1.6
Commercial Kitchen Appliances†	1.7	18.6	3.6	12.3
Commercial Custom Measures	1.3	1.7	1.6	1.8
Commercial Clothes Washers†	1.2	1.8	1.5	4.1
Commercial Building Optimization	1.0	2.1	0.8	2.7
Commercial Network Energy Management	-	1.6	0.2	1.9
	3.3	2.7	2.5	3.0
INDUSTRIAL				
Performance Optimization	2.5	2.1	3.3	2.7
Natural Gas Optimization	0.8	1.2	1.9	1.3
	2.0	1.7	3.0	2.4
DISCONTINUED/COMPLETED PROGRAMS†	18.2	5.4	2.4	8.9
	18.2	5.4	2.4	8.9
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	17.4	1.3	2.2	1.7
	17.4	1.3	2.2	1.7
OVERALL: PROGRAM COSTS	2.9	2.1	2.5	2.5
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	2.7	1.7	2.2	1.9

* Includes all Affordable Energy Fund & Furnace Replacement Program expenditures and external funding.
** "Total" values represent the results of the program/portfolio since its inception.
Ø Includes the present value of projected future commitment payment receipts.
† Includes water savings benefits.
^ Support costs contain DSM support programs, basic information services and program support costs.
^^ Plan estimates are from the 2012 Base DSM Forecast.
Note: Increased or decreased natural gas benefits resulting from electric incentive-based programs have been included in the overall calculation.
Benefit/Cost analysis is not calculated for rate/load management programs.
Free driver participation is included in the above figures.

For 2012/13, the combined overall TRC benefit/cost ratio including support costs was 2.7, which surpassed the planned target. All evaluated Power Smart programs, with the exception of the Affordable Energy Program, Commercial Network Energy Management and Natural Gas Optimization Program, were cost-effective under the TRC metric in 2012/13.

A higher TRC benefit/cost metric was realized under the Bioenergy Optimization Program. This can be attributed to costs being 85% lower than planned and much high than expected Hutterite colony participation.

4.5 Fuel Choice

As part of the Provincial Government's climate change plan, in 2011 they announced an upcoming tax and ban on heating with coal. In July 2013, they formally announced phasing in North America's first coal heating ban effective January 1st, 2014, with a grace period up to July 1st, 2017 if an approved conversion plan was filed by June 30th, 2014.

To assist customers, Manitoba Hydro provided information on the fuel source options available to a number of Hutterite colonies. As a result of these efforts, nineteen colonies switched to biomass, with savings already included under the Bioenergy Optimization Program. In addition, twenty-three colonies switched to natural gas.

The following table outlines the impacts of the Hutterite colonies that switched to natural gas. It contains the avoided energy and demand impacts, as well as the increased natural gas consumption.

These impacts are included in the report for information purposes only and not have been included in the tabulation of overall Power Smart program savings or metrics.

Exhibit 4.5
Fuel Choice Savings

CONVERSION TO NATURAL GAS FROM:	Annual Energy Savings (GW.h savings at meter)		Annual Demand Savings (MW savings at meter)		Increased Natural Gas Consumption (millions of m^3)	
	2012/13	Total*	2012/13	Total*	2012/13	Total*
Lignite Coal	50.5	52.5	19.7	20.4	5.8	6.0
Sub-bituminous Coal	3.0	3.0	1.2	1.2	0.2	0.2
Biomass (Oat Pellets)	1.2	1.2	0.5	0.5	0.1	0.1
Propane	17.6	19.9	6.8	7.8	2.1	2.4
Total	72.3	76.6	28.1	29.8	8.3	8.8

Note: Figures may not add up due to rounding.
*Cumulative savings to the end of 2012/13.

5.0 Total Power Smart Utility Costs

Total Power Smart utility costs include all costs incurred by the utility in the planning, development, design, implementation and evaluation of the Power Smart programs.

Program costs are attributed to a specific program and include program administration costs and incentive costs, while support costs are associated with activities supporting Power Smart programs which cannot be assigned to any one specific program. These costs include activities such as Power Smart promotions (general branding), promoting sustainability and standards, and DSM administration (overall planning and evaluation). Support costs also include costs attributed to running DSM support programs and the basic information portion of the efficiency programs.

5.1 Summary of Total Power Smart Utility Costs

Exhibit 5.1 summarizes the utility costs of the Power Smart programs cumulative to the end of 2012/13. The reported utility costs are presented in nominal dollars and detail actual accounting expenditures to 2012/13 for all Power Smart initiatives and activities.

Exhibit 5.1
Summary of Utility Costs Cumulative to 2012/13

UTILITY COSTS	Cumulative
	millions of nominal dollars
TOTAL UTILITY COSTS	
Program Cost	370.5
Support Cost	83.5
	454.0
TOTAL UTILITY COSTS	454.0

Note: Support costs include both DSM support programs and support activity costs, but do not include Affordable Energy Fund or Furnace Replacement Program expenditures.
Figures may not add due to rounding.

As of March 31st, 2013, Manitoba Hydro had invested $454 million in the Power Smart initiative. The highest component of this expenditure was the program utility costs at $371 million, which makes up 82% of total expenditures cumulative to 2012/13.

5.2 Utility Costs by Program

Exhibits 5.2-A and B outline the costs to the utility for Power Smart initiatives implemented between April 1st, 1989 and March 31st, 2013.

Exhibit 5.2 - A
Utility Costs for Support, DSM Support Programs & Standards

	Actual 2012$	Cumulative nominal $
	thousands of dollars	
DSM SUPPORT PROGRAMS		
DSM Support Programs & Standards Electric Cost	*376*	*2,834*
DSM Support Programs & Standards Natural Gas Cost	*-133*	*2,268*
	243	5,102
BASIC INFORMATION SERVICES		
Basic Information Services Electric Cost	*1,342*	*20,754*
Basic Information Services Natural Gas Cost	*20*	*5,193*
	1,362	25,946
Discontinued/Completed Basic Information Services		
Discontinued/Completed Basic Information Services Electric Cost	*0*	*2,885*
Discontinued/Completed Basic Information Services Natural Gas Cost	*0*	*20*
	0	2,905
SUPPORT COSTS		
Power Smart Communications		
Power Smart Communications Electric Cost	*666*	*15,571*
Power Smart Communications Natural Gas Cost	*545*	*4,347*
	1,210	19,918
Retrofit Demonstrations		
Retrofit Demonstrations Electric Cost	*0*	*9,548*
Retrofit Demonstrations Natural Gas Cost	*0*	*80*
	0	9,628
Integrated Plan/Targets		
Integrated Plan/Targets Electric Cost	127	3,655
Integrated Plan/Targets Natural Gas Cost	104	897
	230	4,551
DSM Administration		
DSM Administration Electric Cost	*178*	*4,103*
DSM Administration Natural Gas Cost	*145*	*1,235*
	323	5,338
DSM Tracking System		
DSM Tracking System Electric Cost	*86*	*620*
DSM Tracking System Natural Gas Cost	*71*	*200*
	157	819
DSM Market Potential Study		
DSM Market Potential Study Electric Cost	*96*	*243*
DSM Market Potential Study Natural Gas Cost	*79*	*226*
	175	469
Commercial Audits		
Commercial Audits Electric Cost	*14*	*149*
Commercial Audits Natural Gas Cost	*14*	*66*
	29	215
Energy Efficiency Screening Studies		
Energy Efficiency Screening Studies Electric Cost	*31*	*126*
Energy Efficiency Screening Studies Natural Gas Cost	*37*	*113*
	68	239
Power Smart Residential Support		
Power Smart Residential Support Electric Cost	*142*	*322*
Power Smart Residential Support Natural Gas Cost	*262*	*482*
	405	804
Sustainabilities & Standards		
Sustainabilities & Standards Electric Cost	*164*	*885*
Sustainabilities & Standards Natural Gas Cost	*136*	*915*
	299	1,801
Power Smart for Business		
Power Smart for Business Electric Cost	*115*	*1,719*
Power Smart for Business Natural Gas Cost	*140*	*931*
	255	2,650
Discontinued/Completed Support Costs		
Discontinued/Completed Support Costs Electric Cost	*0*	*3,157*
Discontinued/Completed Support Costs Natural Gas Cost	*0*	*0*
	0	3,157
Total Support Costs, DSM Support Programs & Standards Electric Cost	*3,336*	*66,572*
Total Support Costs, DSM Support Programs & Standards Natural Gas Cost	*1,421*	*16,972*
TOTAL SUPPORT, DSM SUPPORT PROGRAMS & STANDARDS COSTS	4,757	83,544

Exhibit 5.2 - B

Utility Costs for Incentive-Based Programs

	Actual 2012$	Cumulative nominal $
	thousands of dollars	
EFFICIENCY PROGRAMS		
RESIDENTIAL		
Home Insulation Program		
Home Insulation Program Electric Cost	*1,265*	*13,552*
Home Insulation Program Natural Gas Cost	*1,411*	*16,598*
	2,676	30,150
Affordable Energy Program		
First Nations Program	*185*	*449*
Affordable Energy Program Electric Cost	*113*	*936*
Affordable Energy Program Natural Gas Cost	*642*	*3,399*
	940	4,784
Water & Energy Saver Program		
Water & Energy Saver Program Electric Cost	*775*	*1,828*
Water & Energy Saver Program Natural Gas Cost	*775*	*2,526*
	1,550	4,353
Refrigerator Retirement Program	1,600	3,312
Residential Exploratory Programs		
Residential Exploratory Program Electric Cost	*28*	*54*
Residential Exploratory Program Natural Gas Cost	*0*	*15*
	28	69
Discontinued/Completed Residential Program Costs		
Discontinued/Completed Residential Program Electric Cost	*46*	*22,413*
Discontinued/Completed Residential Program Natural Gas Cost	*5*	*9,618*
	51	32,031
Total Residential Program Electric Cost	*4,012*	*42,543*
Total Residential Program Natural Gas Cost	*2,833*	*32,157*
RESIDENTIAL EFFICIENCY PROGRAM SUBTOTAL	6,845	74,700

Exhibit 5.2 - B (Continued)

Utility Costs for Incentive-Based Programs

	Actual 2012$	Cumulative nominal $
	thousands of dollars	
COMMERCIAL		
Commercial Custom Measures		
Commercial Custom Measures Electric Cost	56	2,742
Commercial Custom Measures Natural Gas Cost	505	1,048
	561	3,790
Commercial Insulation		
Commercial Insulation Electric Cost	451	2,153
Commercial Insulation Natural Gas Cost	1,108	8,116
	1,559	10,268
Commercial Windows		
Commercial Windows Electric Cost	925	5,736
Commercial Windows Natural Gas Cost	796	4,701
	1,721	10,438
Commercial Earth Power Program	265	4,485
Commercial HVAC		
Commercial HVAC Electric Cost	147	1,888
Commercial HVAC Natural Gas Cost	1,179	8,019
	1,325	9,907
CO2 Sensors		
CO2 Sensors Electric Cost	2	8
CO2 Sensors Natural Gas Cost	36	140
	39	148
Internal Retrofit	811	20,084
Commercial Lighting	7,757	75,641
City of Winnipeg Power Smart Agreement	-120	10,533
Commercial Refrigeration	613	2,256
Commercial Building Optimization Program		
Commercial Building Optimization Program Electric Cost	92	498
Commercial Building Optimization Program Natural Gas Cost	92	1,310
	184	1,807
New Buildings Program		
New Buildings Electric Cost	116	1,112
New Buildings Program Natural Gas Cost	1,043	1,750
	1,159	2,862
Commercial Clothes Washers	59	442
Commercial Kitchen Appliances		
Commercial Kitchen Appliances Electric Cost	12	259
Commercial Kitchen Appliances Natural Gas Cost	27	216
	39	475
Commercial Network Energy Management Program	6	202
Commercial Exploratory Programs		
Commercial Exploratory Program Electric Cost	0	1
Commercial Exploratory Program Natural Gas Cost	0	82
	0	83
Discontinued/Completed Commercial Programs		
Discontinued/Completed Commercial Program Electric Cost	11	17,185
Discontinued/Completed Commercial Program Natural Gas Cost	0	944
	12	18,129
Total Commercial Program Electric Cost	11,201	145,224
Total Commercial Program Natural Gas Cost	4,786	26,326
COMMERCIAL EFFICIENCY PROGRAM SUBTOTAL	15,987	171,550

Exhibit 5.2 - B (Continued)

Utility Cost for Incentive-Based Programs

	Actual 2012$	Cumulative nominal $
	thousands of dollars	
INDUSTRIAL		
Performance Optimization Program	2,741	31,654
Natural Gas Optimization Program	753	3,558
Emergency Preparedness	0	159
	3,494	35,371
Discontinued/Completed Industrial Programs		
Discontinued/Completed Industrial Program Electric Cost	*0*	*2,708*
Discontinued/Completed Industrial Program Natural Gas Cost	*0*	*0*
	0	2,708
Total Industrial Program Electric Cost	*2,741*	*34,521*
Total Industrial Program Natural Gas Cost	*753*	*3,558*
INDUSTRIAL EFFICIENCY PROGRAM SUBTOTAL	3,494	38,079
EFFICIENCY PROGRAMS COSTS		
Total Efficiency Program Electric Cost	*17,954*	*222,287*
Total Efficiency Program Natural Gas Cost	*8,372*	*62,041*
EFFICIENCY PROGRAM SUBTOTAL	26,326	284,328
CUSTOMER SELF GENERATION		
Bioenergy Optimization Program		
Bioenergy Optimization Program Electric Cost	*348*	*10,201*
Bioenergy Optimization Program Natural Gas Cost	*0*	*112*
	348	10,312
RATE/LOAD MANAGEMENT PROGRAMS		
Curtailable Rates	5,751	75,843
	5,751	75,843
TOTAL PROGRAM COSTS		
Total Program Electric Cost	*24,053*	*308,330*
Total Program Natural Gas Cost	*8,372*	*62,152*
TOTAL PROGRAM COSTS	32,425	370,483

Note: Figures may not add due to rounding.

5.3 Utility Costs by Energy Source

Exhibit 5.3 provides a summary of electric and natural gas utility costs. Total Power Smart electric initiatives represented 74% of total Power Smart Expenditures in 2012/13 and 83% of Power Smart expenditures to date.

Exhibit 5.3
Summary of Electricity & Natural Gas Utility Costs

	Actual 2012$	Cumulative nominal $
	millions of dollars	
ELECTRICITY		
Program Cost	24.1	308.3
Support Cost	3.3	66.6
	27.4	374.9
NATURAL GAS		
Program Cost	8.4	62.2
Support Cost	1.4	17.0
	9.8	79.1
TOTAL UTILITY COSTS (ELECTRICITY + NATURAL GAS)	37.2	454.0

Note: Support costs include both DSM support programs and support activity costs, but do not include Affordable Energy Fund or Furnace Replacement Program expenditures.
Figures may not add due to rounding.

5.4 The Affordable Energy Fund

The Affordable Energy Fund was established in 2006/07 through the Winter Heating Cost Control Act and it supports Manitoba Hydro's sustainable development initiatives. The purpose of the fund is to provide support for programs and services that achieve specific objectives including encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, lower income customers and seniors, and encouraging the use of alternative energy sources such as renewable energy.

Exhibit 5.4 provides a summary of Affordable Energy Fund expenditures.

Exhibit E.14

Summary of Affordable Energy Fund Expenditures

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative
				thousands of nominal dollars				
Affordable Energy Program	256	219	893	1,672	2,666	3,131	3,332	12,168
Geothermal Support								
Waverley West Demonstration Project*	619	252	5	0	-1	-1	-1	873
Earth Power Loan Subsidy	0	19	69	105	108	108	91	500
Province of Manitoba Cooperative Advertising	0	0	18	0	0	0	0	18
Geothermal Support Total	619	270	92	104	108	107	91	1,391
Community Support & Outreach	0	0	35	130	133	139	114	551
Oil & Propane Heated Homes	0	75	85	31	32	24	0	246
Special Projects								
Res. Energy Assessment Services (ecoENERGY Audits)	0	61	241	85	119	39	0	545
Oil & Propane Furnace Replacement	0	0	6	36	42	17	10	112
Res. Solar Water Heating Program	0	0	89	119	56	11	10	285
Power Smart Residential Loan	0	0	0	130	312	354	510	1,306
Oil & Propane Heated Homes - Additional Funding	0	0	0	0	0	10	26	37
Special Projects Total	0	61	336	371	529	431	556	2,284
Community Energy Development								
ecoENERGY Program Funding - Additional Funding	0	0	0	0	0	2,817	1,241	4,058
Community Energy Development Total	0	0	0	0	0	2,817	1,241	4,058
DSM INITIATIVES SUBTOTAL	875	625	1,441	2,308	3,468	6,649	5,334	20,700
Manitoba Electric Bus	0	0	0	0	0	700	75	775
Energy & Resource Fund	0	0	0	750	0	0	0	750
Fort Whyte EcoVillage	0	0	0	0	0	120	0	120
Diesel Community Green Pilot Demonstration	0	0	0	0	0	3	-3	0
TOTAL EXPENDITURES	875	625	1,441	3,058	3,468	7,472	5,406	22,345

* Negative costs represent loop lease payments from customer to Manitoba Hydro.
** Reversal of an incorrect charge that took place in 2011/12 is indicated by the negative cost.

5.5 Furnace Replacement Budget

The Furnace Replacement Budget was established in 2007/08 as a result of Public Utility Board Order 99/07. The purpose of the budget is to support the implementation of a natural gas Furnace Replacement Program for lower income customers.

In 2012/13 alone, customers installed 630 furnaces and 9 boilers through the Furnace Replacement Program. Cumulatively, 2,525 furnaces and 57 boilers have been installed to the end of 2012/13 as a result of the program.

Exhibit 5.5 outlines the Furnace Replacement Expenditures.

Exhibit 5.5
Summary of Furnace Replacement Expenditures

	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative
			thousands of nominal dollars			
Natural Gas Furnace Replacement	264	815	1,312	1,627	2,167	6,185
TOTAL EXPENDITURES	264	815	1,312	1,627	2,167	6,185

Appendix A

Sources of Evaluation & Planning Estimates

Many sources are used to estimate load savings and utility costs resulting from the Power Smart programs. These include:

Evaluation Estimate Sources

Impact Evaluation Reports:

Impact evaluation reports are prepared annually for the Power Smart programs to identify net program load savings and costs, as well as the cost-effectiveness of these savings. Net savings and costs differ from gross savings and costs as they take into consideration factors such as free riders, free drivers, heating/cooling interactive effects and persistence.

A number of variables potentially affect the cost-effectiveness of Power Smart programs. These variables include energy, demand and natural gas reduction; hours of operation; measure persistence; average measure life; measure reinvestment and changes in marginal cost values.

Life-to-Date Expenditure Report:

The utility costs cumulative to 2012/13 are tracked annually from the Annual DSM Expenditure Report.

Engineering Estimates:

Engineering expertise is used to quantify usage and savings data. Computer simulation and modeling may also be utilized.

Sales & Market Data:

In-depth market knowledge, product specifications and ratings, sales and replacement data, etc. are used to determine market acceptance and uptake.

Planning Estimate Sources

2012/13 Planning Estimates:

The 2012/13 electric and natural gas planning estimates were taken from the 2012 Base DSM Forecast.

In all cases, the 2012 Base DSM Forecast estimates were used regardless of delays in program launches or modifications. Consistent usage of the same plan helps reduce the probability of errors and provides a verifiable public target to compare against. Utilizing the same source information also helps ensure that a realistic and objective evaluation of the programs/portfolio is conducted, and improves the reliability and verifiability of the Power Smart Annual Review.

2026/27 Planning Estimates:

The 2026/27 electric planning targets for energy and demand savings are from the 2012 Base DSM Forecast which includes forecasts for 2012/13 through 2026/27. The 1992/93 through 2011/12 planning estimates for energy and demand savings are from the respective Power Smart Resource Options reports or Power Smart Plan. Electric long range planning targets did not exist prior to 1992/93.

The 2026/27 natural gas planning targets are from the 2012 Base DSM Forecast which includes forecasts for 2012/13 through 2026/27. Natural gas long range planning targets did not exist prior to 2005/06.

The 2012/13 through 2026/27 planning estimates for utility costs are included in the Integrated Financial Forecast report current during the evaluation year (IFF12).

The planning estimates for the years 1990/91 through 2011/12 are included in the following Integrated Financial Forecast reports: IFF90-4, IFF91-4, IFF92-4, IFF93-3, IFF94-2, IFF95-1, IFF96-1, IFF97-1, IFF98-1, IFF99-1, IFF00-1, IFF01-1, IFF02-1, IFF03-1, IFF04-1, IFF05-1, IFF06-1, IFF07-1, IFF08-1, IFF09-1, IFF10-1 and IFF11-2.

Appendix B

Explanation of Benefit/Cost Ratios Used in DSM Metrics

Total Resource Cost (TRC) Metric

The Total Resource Cost (TRC) metric is used to assess the benefits of an energy efficiency program irrespective of who realizes the benefits and who pays the costs. Any economic transfers between Manitoba Hydro and the participating customer are excluded from the calculation.

The TRC is calculated based on the following formula:

$$TRC = \frac{\text{PV (Marginal Benefit)}}{\text{PV (Total Program Administration + Incremental Product Cost)}}$$

Where:

- For electricity, the marginal benefit includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (i.e. electric transmission facilities) and measurable non-energy benefits (i.e. water savings).
- For natural gas, the marginal benefit includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions and measurable non-energy benefits (i.e. water savings).
- Total program administration costs include the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program except for customer incentive costs.
    - o Note: The City of Winnipeg Power Smart Agreement evaluation treats commitment payments paid by Manitoba Hydro as administration costs. Projected future commitment payment cash inflows to Manitoba Hydro are netted against commitment payments made to the City of Winnipeg.
- Incremental product costs include the total incremental costs associated with implementing a Power Smart measure. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the energy efficient technology.

Levelized Utility Cost (LUC) / Rate Impact Measure (RIM) Ratio

The Levelized Utility Cost (LUC) is used to provide an economic cost value for the energy saved by an energy efficiency program. The LUC provides the total cost of the conserved energy based upon the utility's investment on behalf of the ratepayer on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different time frames.

The Rate Impact Measure (RIM) metric is used in conjunction with the LUC to provide an indication of the long term impact of an energy efficient program on energy rates. This metric is especially valuable in interpreting the LUC of electric energy efficiency programs due to the varying summer/winter values of Manitoba Hydro's marginal cost. This metric is a benefit/cost ratio that represents the economic impact of a program from the ratepayer's perspective. All program-related savings and costs incurred by the utility, including revenue loss and incentive payments, are taken into account in this assessment.

The LUC and RIM are calculated based on the following formulas:

$$\text{LUC} = \frac{\text{PV (Utility Program Administration Costs + Incentives)}}{\text{PV (Energy)}}$$

$$\text{RIM} = \frac{\text{PV (Utility Marginal Benefit)}}{\text{PV (Revenue Loss + Utility Program Administration Costs + Incentives)}}$$

Where:

- Utility program administration costs include the costs to Manitoba Hydro associated with program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program except for customer incentive costs.
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.
- Energy includes the annual energy savings associated with the energy efficiency measure.
- For electricity, the utility marginal benefit includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (i.e. electric transmission facilities).
- For natural gas, the utility marginal benefit includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs and the value of reduced greenhouse gas emissions.
- Revenue loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer bill reductions)
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

Levelized Resource Cost (LRC)

The Levelized Resource Cost (LRC) is used to provide an economic cost value for the energy saved through an energy efficiency program. The LRC provides the total resource cost of the conserved energy on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different time frames.

The LRC is calculated based on the following formula:

$$LRC = \frac{PV\ (\text{Total Program Administration} + \text{Incremental Product Cost})}{PV\ (\text{Energy})}$$

Where:

- Total program administration costs include the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program except for customer incentive costs.
- Incremental product cost is the difference in cost between the energy efficient technology and the standard technology that would have been installed in the absence of the energy efficient technology.
- Energy includes the annual energy savings associated with the energy efficiency measure.

Appendix C

Total Power Smart Participation

Power Smart Participants Annual Increments*†	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	**2012/13**	***Cumulative***
Residential																									
Residential DSM Support Programs																									
Financing Programs																									
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	4,873	3,386	4,211	5,114	6,325	7,222	7,427	7,391	6,453	5,262	6,492	6,202	70,358
Power Smart Residential PAYS Program	-	-	-	-	-	-	-	-	-	-	-	-												52	52
Residential Earth Power Loan																									
Geothermal Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	35	92	185	139	85	224	207	114	53	52	24	1,210
Solar Hot Water Heating Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7	-	-	14
Financing Programs Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	4,873	3,421	4,303	5,299	6,464	7,307	7,651	7,598	6,574	5,322	6,544	6,278	71,634
ecoENERGY[i]	-	-	-	-	-	-	-	-	-	-	-	-	411	1,094	4,085	5,298	6,939	5,001	3,171	4,967	7,009	3,428	11,683	1,186	54,272
Mail-In/On-Line Energy Assessments	-	-	-	-	-	-	-	-	-	-	-	-	570	532	338	378	234	455	421	251	153	263	416	286	4,297
Residential DSM Support Programs SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	5,854	5,047	8,726	10,975	13,637	12,763	11,243	12,816	13,736	9,013	18,643	7,750	130,203
Residential DSM Support Porgrams Discontinued/Completed Programs																									
WISE Home	-	-	-	-	-	-	-	-	-	-	-	-	297	506	570	900	859	612	312	425	450	460	-	-	5,391
Energy Saver Presentations	-	-	-	-	-	-	-	-	-	-	-	-	58	1,156	453	467	337	610	392	291	192	-	-	-	3,956
New Home Workshops	-	-	-	-	-	-	-	-	-	-	-	-	40	305	116	158	119	116	-	-	-	-	-	-	854
R-2000 Component of the 'New Home Program'[ii]	-	-	-	-	-	-	-	-	-	-	-	-	12	19	32	-	-	-	-	-	-	-	-	-	63
Solar Water Heating (Incentive Component)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18	-	-	36
Residential Earth Power																								-	
Earth Power Consumer Workshops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150	475	63	-	-	-	-	-	-	688
Residential DSM Support Programs Discontinued/Completed Programs	-	-	-	-	-	-	-	-	-	-	-	-	407	1,986	1,171	1,675	1,790	1,401	704	716	660	478	-	-	10,988
RESIDENTIAL DSM Support Pograms TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	6,261	7,033	9,897	12,650	15,427	14,164	11,947	13,532	14,396	9,491	18,643	7,750	141,191
Residential Incentive-Based Programs																									
Home Insulation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	459	1,419	5,211	4,551	4,578	5,093	3,656	3,678	2,867	31,512
Refrigerator Retirement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,437	8,298	16,735
Water & Energy Saver	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38,448	33,411	27,420	99,279
Affordable Energy Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139	143	716	2,056	1,908	1,653	6,615
Residential Incentive-Based Programs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	459	1,419	5,211	4,690	4,721	5,809	44,160	47,434	40,238	154,141
Residential Incentive-Based Discontinued/Completed Programs																									
Compact Fluorescent Lighting[v]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,663	26,623	17,296	28,933	73,228	99,817	75,821	-	-	343,381
Programmable Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,948	2,230	-	-	-	-	-	7,178
Outdoor Timer	6,169	8,954	8,134	4,812	4,160	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32,229
Refrigerator/Freezer Buy-Back Pilot	-	-	474	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	474
EE Water Tank/ Water Savings Measures of the 'No Worry Plan'	-	-	-	-	-	-	-	201	709	681	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,591
Energy Efficient Light Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,047	2,380	2,691	1,126	3,351	2,305	-	12,900
New Home	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	126	217	204	220	205	230	142	1	1,381
Seasonal LEDs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,900	10,880	8,144	4,956	-	-	-		25,880
Energy Efficient Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,374	15,436	13,277	2,451	-	-		41,538
High Efficiency Furnace/Boiler Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,228	7,028	6,630	7,295	5,190	-	-		27,371
Residential Incentive-Based Discontinued/Completed Programs	6,169	8,954	8,608	4,812	4,160	-	-	201	709	681	-	-	-	-	-	21,699	29,877	51,790	63,957	101,667	108,789	79,402	2,447	1	493,923
Residential Incentive-Based TOTAL	6,169	8,954	8,608	4,812	4,160	-	-	201	709	681	-	-	-	-	-	22,158	31,296	57,001	68,647	106,388	114,598	123,562	49,881	40,239	648,064
Residential TOTAL	6,169	8,954	8,608	4,812	4,160	-	-	201	709	681	-	-	6,261	7,033	9,897	34,808	46,723	71,165	80,594	119,920	128,994	133,053	68,524	47,989	789,255
Commercial																									
Commercial DSM Support Programs																									
Religious Buildings Initiative	-	-	-	-	-	-	-	-	-	-	-	-	14	6	25	13	34	63	40	19	9	5	3	-	231
Power Smart Recreation Facility Survey	-	-	-	-	-	-	-	-	-	-	-	-	30	5	6	5	4	5	6	4	1	2	1	-	69
Commercial DSM Support Programs SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	44	11	31	18	38	68	46	23	10	7	4	-	300
Commercial DSM Support Programs Discontinued/Completed Programs																									
Power Smart Energy Manager[iii]	-	-	-	-	-	-	-	-	-	-	-	18	-	20	-	-	-	-	-	-	-	-	-	-	38
Commercial DSM Support Programs Discontinued/Completed Programs	-	-	-	-	-	-	-	-	-	-	-	18	-	20	-	-	-	-	-	-	-	-	-	-	38
Commercial DSM Support Programs TOTAL	-	-	-	-	-	-	-	-	-	-	-	18	44	31	31	18	38	68	46	23	10	7	4	-	338

Power Smart Participants ***Annual Increments*†***	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	**2012/13**	Cumulative
Commercial Incentive-Based Programs																									
Custom Measures**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	3	1	13	8	13	27	69
Building Envelope	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	179	244	371	453	404	337	2,160
Commercial HVAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	112	131	107	89	64	93	695
Internal Retrofit	-	-	-	8	15	21	30	24	49	60	37	52	42	55	31	135	425	59	32	68	42	39	36	29	1,289
Commercial Lighting	-	-	-	129	634	556	488	264	235	384	178	122	152	184	373	742	871	999	1,116	1,292	1,111	991	788	748	12,357
Commercial Building Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	4	0	2	9
Commercial Earth Power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28	15	11	23	19	13	10	119
Commercial Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	27	17	41	36	31	565	729
City of Winnipeg Power Smart Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	4	5	11	274	9	7	1	4	2	4	1	322
Commercial Kitchen Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	27	16	11	6	81
Commercial Clothes Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	160	37	21	17	244
New Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	15	22
Network Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	2	-	-	8
Commercial Incentive-Based Programs SUBTOTAL	-	-	-	137	649	577	518	288	284	444	215	174	194	243	409	888	1,570	1,382	1,491	1,796	1,907	1,696	1,392	1,850	18,104
Commercial Incentive-Based Discontinued/Completed Programs																									
Sentinel Lighting	-	-	65	63	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199
Roadway Lighting	-	-	-	73	71	55	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199
Commercial Construction & Renovation	-	-	-	-	-	-	-	46	41	40	54	42	56	76	88	102	232	-	-	-	-	-	-	-	777
Livestock Waterer	-	-	-	-	129	96	57											-	-	-	-	-	-	-	282
Agricultural Demand Controller	-	-	-	-	24	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
Infrared Heat Lamps	-	-	-	-	1,016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,016
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	656	202	224	97	-	-	-	1,179
Parking Lot Controllers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	253	296	89	137	168	82	10	1,035
Agricultural Heat Pads	-	-	-	-	-	-	-	-	-	18	22	7	11	14	10	12	9	5	6	4	10	7	48	35	218
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	330	378	-	-	708
Commercial Incentive-Based Discontinued/Completed Programs SUBTOTAL	-	-	65	136	1,310	161	57	46	41	58	76	49	67	90	98	114	241	914	504	317	574	553	130	45	5,647
Commercial Incentive-Based TOTAL	-	-	65	273	1,959	738	575	334	325	502	291	223	261	333	507	1,002	1,811	2,296	1,995	2,113	2,481	2,249	1,522	1,895	23,751
Commercial TOTAL	-	-	65	273	1,959	738	575	334	325	502	291	241	305	364	538	1,020	1,849	2,364	2,041	2,136	2,491	2,256	1,526	1,895	24,089
Industrial																									
Industrial Incentive-Based Programs																									
Performance Optimization	-	-	-	-	3	1	4	4	4	8	2	7	15	22	28	44	46	44	66	84	97	72	55	71	677
Natural Gas Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	14	14	13	14	75
Industrial Incentive-Based Programs	-	-	-	-	3	1	4	4	4	8	2	7	15	22	28	44	46	44	76	94	111	86	68	85	752
Industrial Incentive-Based Discontinued/Completed Programs																									
High Efficiency Motors	-	-	24	157	199	228	181	178	191	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,158
Industrial Incentive-Based Discontinued/Completed Programs	-	-	24	157	199	228	181	178	191	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,158
Customer Self-Generation Programs																									
Bioenergy Optimization Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	2	22	22
Customer Self-Generation Programs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1	2	22	22
Rate/Load Management Programs																									
Curtailable Rates[iv]	-	-	-	-	-	-	-	-	-	-	2	2	2	3	4	4	4	4	4	4	4	3	3	3	5
Rate/Load Management Programs	-	-	-	-	-	-	-	-	-	-	2	2	2	3	4	4	4	4	4	4	4	3	3	3	5
Industrial TOTAL	-	-	24	157	202	229	185	182	195	8	4	9	17	25	32	48	50	49	81	99	116	90	73	110	1,937
DSM SUPPORT PROGRAMS ACTIVE & DISCONTINUED/COMPLETED SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	18	6,305	7,064	9,928	12,668	15,465	14,232	11,993	13,555	14,406	9,498	18,647	7,750	141,529
INCENTIVE-BASED PROGRAMS ACTIVE & DISCONTINUED/COMPLETED SUBTOTAL	6,169	8,954	8,697	5,242	6,321	967	760	717	1,229	1,191	295	232	278	358	539	23,208	33,157	59,346	70,723	108,600	117,195	125,901	51,476	42,244	673,752
ALL PROGRAMS ACTIVE & DISCONTINUED/COMPLETED TOTAL	**6,169**	**8,954**	**8,697**	**5,242**	**6,321**	**967**	**760**	**717**	**1,229**	**1,191**	**295**	**250**	**6,583**	**7,422**	**10,467**	**35,876**	**48,622**	**73,578**	**82,716**	**122,155**	**131,601**	**135,399**	**70,123**	**49,994**	**815,281**

[†] Customers may participate in more than one Power Smart Program.
*Participation is measured by completed projects, and excludes free drivers and market transformation.
** A summation of annual participation columns will not necessarily correspond with the total participation to date. This is a result of the Curtailable Rates Program participation (see footnote iv).
[i] The program offering in-home energy assessments prior to 2007/08 was known as the EnerGuide for Houses program. As Manitoba Hydro highly subsidized the evaluation cost of Amerispec and EnerGuy participants, they are included in the participation figures for 2011/12 and 2012/13.
[ii] Starting in 2004/05, the R-2000 Program was grouped into the Power Smart New Home Program.
[iii] Power Smart Energy Manager Program participation is measured by schools. Schools that joined the program in 2000/01 participated for 4 years, and schools that joined in 2002/03 participated for 2 years.
[iv] Annual participation represents the number of customers who participate each year. Since most customers participate year after year, the cumulative number represents the actual number of customers who have participated to date.
[v] Participation in the CFL Program is defined as 1 household.

Appendix D

Synopsis of Discontinued Power Smart Incentive-Based Programs

Residential Programs

Outdoor Timer Program

This program encouraged the use of outdoor timers to control block heaters and interior car warmers at existing homes.

Refrigerator/Freezer Buy-Back Pilot

This pilot program encouraged the removal of older, inefficient second refrigerators and freezers in existing homes.

Residential Shower Head Pilot

This pilot program encouraged the installation of energy efficient shower heads in existing homes.

Energy Efficient Water Saving Measures Component of the "No Worry Plan"

This program encouraged participants of the "No Worry Plan" hot water tank program to install energy saving devices (faucet aerators, heat traps, energy efficient shower heads and pipe wrap) as part of a bonus package when installing new hot water tanks.

Energy Efficient Water Tank Component of the "No Worry Plan"

This program encouraged residential customers with electric hot water heaters to purchase, finance or lease the most energy efficient water heater available when replacing or installing new electric water heaters.

New Home Program

This program provided customers in the residential new construction market with prescriptive Power Smart standards and incentives to implement energy saving features and construction techniques into the construction of new homes.

Compact Fluorescent Lighting Program

This program encouraged residential customers and property managers of multi-unit residential buildings to install energy efficient compact fluorescent light bulbs.

Seasonal LED Lighting Program

This program encouraged customers to replace their existing incandescent seasonal light strings with energy efficient LED light strings.

High Efficiency Furnace/Boiler Program

This program encouraged residential customers to replace their existing natural gas furnaces or boilers with ENERGY STAR-qualified high efficiency natural gas furnaces or boilers.

Residential Appliances Program

This program encouraged residential customers to purchase ENERGY STAR-qualified clothes washers and chest freezers.

Programmable Thermostat Pilot

This pilot program encouraged customers to replace non-programmable thermostats with ENERGY STAR programmable models.

Energy Efficient Light Fixtures Program

The Energy Efficient Light Fixtures Program provided financial incentives to residential customers and property managers of multi-unit residential buildings to encourage the installation of ENERGY STAR® qualified light fixtures, dimmer switches and LED night lights.

Incentive Component of the "Solar Water Heating Program"

In partnership with Natural Resources Canada, this program encouraged homeowners to purchase solar water heating systems.

Commercial Programs

Roadway Lighting Program

This program converted existing incandescent and mercury vapor street lighting to more energy efficient, high pressure sodium lighting.

Sentinel Lighting Program

This program encourages the conversion of yard lighting and sentinel lighting from mercury vapor and incandescent lighting to the more energy efficient, high pressure sodium lighting.

Commercial Shower Head Pilot

This pilot program encouraged commercial operations to retrofit shower facilities with energy efficient shower heads.

Infrared Heat Lamps

This program encouraged swine farrowing operations to use energy efficient heat lamps in place of standard heat lamps.

Agricultural Demand Controller

This program encouraged large agricultural operations to install demand controllers to reduce peak demand consumption.

Livestock Waterer

This program encouraged dairy and cattle operations to install energy efficient waterers to reduce energy and demand consumption.

Air Barrier Component of the "Commercial Construction Program"

This program encouraged commercial customers to install greater efficiency air barriers when retrofitting their building's envelope.

Air Conditioning Component of the "Commercial Construction Program"

This program encouraged commercial customers to replace their existing air conditioning system with a more energy efficient system.

Commercial Parking Lot Controllers

This program encouraged customers to implement parking lot controller technology to effectively manage electricity usage in their parking lots.

Agricultural Heat Pads

This program encouraged owners of swine barns to replace the traditional heat lamps in their hog farrowing crates with energy efficient heat pads.

Commercial Rinse & Save

The program offered operators of restaurants or food services businesses the free installation of a low-flow pre-rinse spray valve.

Power Smart Energy Manger

This program provided information, training and support for Manitoba school divisions to hire dedicated energy managers. During 2012/13, this program was undergoing redesign.

Power Smart Shops

This program encouraged small independent commercial customers to fully convert their buildings to a Power Smart Shop level of efficiency. During 2012/13, this program was undergoing redesign.

Industrial Programs

High Efficiency Motors

This program encouraged the installation of high efficiency motors in industrial and commercial operations.

Appendix E

Curtailable Rates Program Information & Methodology

- The Curtailable Rates Program provides incentives to large industrial customers who curtail their electrical load when called upon by Manitoba Hydro. Incentives are provided by way of a credit on the customer's monthly energy bill.

- 2012/13 reported demand savings for the Curtailable Rates Program are based on a methodology where curtailments throughout the year are analyzed to determine the amount of curtailable load that can be expected to be on the system at the time a curtailment is called. This methodology has been in place since 2000/01. For previous methodology details, refer to the appropriate Power Smart Annual Review.

- Curtailable Rates Program targets are from the 2012 Base DSM Forecast.

- Curtailable Rate Program targets and savings are adjusted for efficiency. This adjustment is made to equate load available for curtailment to that of an actual generator. Curtailments are not as efficient since there is potential risk customers may not curtail at all or may not curtail in time for Manitoba Hydro's system peak. The efficiency factor is based on the curtailment option selected by the customer.

- Savings resulting from the Curtailable Rates Program are available as long as the service offering continues, whether or not actual curtailments are made at the time of system peak or at any other time. Curtailments may be made to:
    - Re-establish contingency reserves;
    - Maintain planning reserve obligations;
    - To protect firm load when reserves are insufficient to avoid curtailing firm load; and to
    - Meet Manitoba Hydro's non-spinning reserves to the extent necessary.

- The expected availability of this load and not the timing of its dispatch determine the future benefits of demand savings for this program.

- Under the 2012/13 Power Smart Annual Review, the Curtailable Rates Program has been treated as an incentive-based program. This is consistent with treatment in the 2012 Base DSM Forecast. As a rate/load management program, cost-effectiveness metrics are not reported.

Appendix F

Energy Savings -Incentive-Based Programs

2012/13 Annual Energy Savings - GW.h
Electric Incentive Based Programs

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																	
Refrigerator Retirement Program	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	-	-	-	-	9.9	-
Home Insulation	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	7.0	7.0
Water & Energy Saver	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.5	3.5
Affordable Energy Program	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	3.2	3.2
	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	12.1	12.1	12.1	12.1	23.7	13.8
DISCONTINUED/COMPLETED																	
New Homes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Compact Fluorescent Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Outdoor Timer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Res Hot Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heater Rental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficient Light Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retrofit/Demonstration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RESIDENTIAL TOTAL	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	12.1	12.1	12.1	12.1	23.7	13.9
COMMERCIAL																	
Commercial Lighting	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	31.6	31.6
Commercial Refrigeration	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	14.3	14.3
New Buildings	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.7	4.7
Commercial Insulation*	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.6	3.6
Commercial Windows*	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.4	2.4
Commercial Earth Power	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.4	2.4
Internal Retrofit	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.8	1.8
HVAC - Chillers	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3
Custom	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Commercial Clothes Washers	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
City of Winnipeg Agreement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Commercial Building Optimization	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1						0.1	-
HVAC - CO2 Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Commercial Kitchen Appliances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.8	55.7	55.7	55.7	55.7	55.7	63.6	63.5
DISCONTINUED/COMPLETED																	
Agricultural Heat Pads	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.0
Parking Lot Controllers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Showerhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Infrared Heat Lamp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roadway Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sentinel Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Barrier	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.0
COMMERCIAL TOTAL	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.6	57.5	57.5	57.5	57.5	57.5	65.6	65.5
INDUSTRIAL																	
Performance Optimization	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	75.6	75.6
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	75.6	75.6
DISCONTINUED/COMPLETED																	
Industrial (Basic)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retrofit/Demonstration GSL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Efficiency Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INDUSTRIAL TOTAL	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	68.7	75.6	75.6
EFFICIENCY PROGRAMS SUBTOTAL	147.1	147.1	147.1	147.1	147.1	147.1	147.1	147.1	147.1	147.1	147.0	138.4	138.4	138.4	138.4	164.9	155.0
CUSTOMER SELF-GENERATION PROGRAMS																	
BioEnergy Optimization Program	82.5	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	90.7	55.7
	82.5	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	90.7	55.7
RATE/LOAD MANAGEMENT PROGRAMS																	
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	229.6	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.6	189.0	189.0	189.0	189.0	N/A	N/A
GW.h IMPACTS (at generation)	255.7	220.6	220.6	220.6	220.6	220.6	220.6	220.6	220.6	220.6	220.5	210.6	210.6	210.6	210.6	255.7	210.6

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Persisting Energy Savings - GW.h
Electric Incentive Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Home Insulation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7	4.2	10.7	16.5	22.1	28.4	33.8	38.7	38.7	44.1	44.1
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	10.9	12.4	-
Water & Energy Saver	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.5	9.5	10.8	10.8
Affordable Energy Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.1	2.0	4.2	6.4	6.4	7.3	7.3
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7	4.2	10.7	17.0	23.2	30.4	38.0	65.6	65.6	74.8	62.3
DISCONTINUED/COMPLETED																										
Compact Fluorescent Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.1	15.4	20.6	28.1	49.9	77.7	92.1	92.1	92.1	105.0	102.5
Outdoor Timer	5.0	8.9	15.3	20.6	24.8	29.2	30.9	34.7	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	41.6	41.6
Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6	7.6	12.1	12.7	12.7	12.7	12.7	14.5	14.5
New Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.6	1.9	2.9	3.7	4.3	5.0	5.5	5.5	6.3	6.3
Energy Efficient Light Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	1.0	2.1	2.6	3.7	4.5	4.5	5.1	5.1
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	1.3	2.3	3.1	3.2	3.2	3.2	3.2	3.7	3.7
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.3	1.3	1.3	1.3	1.4	1.4
Res Hot Water	-	-	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Water Heater Rental	-	-	-	-	-	-	-	0.1	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5.0	8.9	15.7	21.0	25.1	29.6	31.3	35.1	37.2	37.5	37.6	37.6	37.6	37.6	37.6	45.8	53.7	65.4	79.8	108.8	139.8	156.0	157.2	157.2	179.2	176.7
RESIDENTIAL TOTAL	5.0	8.9	15.7	21.0	25.1	29.6	31.3	35.1	37.2	37.5	37.6	37.6	37.6	37.6	37.6	47.5	57.9	76.1	96.9	132.0	170.2	193.9	222.8	222.8	253.9	239.0
COMMERCIAL																										
Commercial Lighting	-	-	-	2.9	17.0	35.9	55.0	61.2	67.4	85.4	90.8	94.9	100.2	105.6	116.2	132.6	153.1	175.8	193.9	218.9	239.5	258.7	281.2	281.2	320.6	320.6
Internal Retrofit	-	-	-	0.2	1.2	2.7	3.3	3.8	4.3	4.9	5.4	5.9	6.1	6.9	9.4	12.2	14.4	17.0	18.0	19.8	29.5	41.4	53.6	53.6	61.1	61.1
Commercial Earth Power	-	-	-	-	-	-	-	0.3	1.1	1.8	2.9	3.2	4.0	5.1	7.8	8.8	11.1	15.3	18.6	20.2	23.6	26.0	27.8	27.8	31.7	31.7
Custom	-	-	-	-	-	-	-	0.4	0.4	2.6	10.0	10.8	11.7	12.2	12.8	12.8	12.9	13.1	15.4	15.9	17.4	18.8	20.2	20.2	23.0	23.0
Commercial Insulation*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.9	4.1	6.6	9.7	12.5	12.5	14.2	14.2
Commercial Windows*	-	-	-	-	-	-	-	0.1	0.4	0.6	0.7	0.9	1.0	1.4	1.8	2.3	3.2	3.9	4.5	5.2	7.3	9.7	11.7	11.7	13.4	13.4
City of Winnipeg Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.6	1.2	7.6	9.6	10.1	10.3	10.8	11.1	11.5	11.5	13.1	13.1
Commercial Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	3.0	4.3	5.5	7.0	8.7	8.7	9.9	9.9
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.5	3.7	4.1	4.3	4.8	5.3	7.1	8.2	8.2	9.3	9.3
New Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	2.3	2.6	2.6
Commercial Building Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.6	0.9	0.9	0.9	1.0	-
Commercial Kitchen Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.5	0.6	0.7	0.7	0.8	0.8
Commercial Clothes Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.5	0.5	0.5	0.5
Network Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1
	-	-	-	3.1	18.2	38.6	58.3	65.8	73.6	95.3	109.7	115.6	123.1	131.1	148.5	172.2	206.0	240.7	269.7	304.3	347.0	391.6	440.0	440.0	501.6	500.6
DISCONTINUED/COMPLETED																										
Parking Lot Controllers	-	-	-	-	-	-	-	0.8	1.6	3.7	4.1	4.4	5.9	6.8	8.8	11.5	20.0	27.9	30.5	32.4	34.9	38.1	39.4	39.4	44.9	44.9
Agricultural Heat Pads	-	-	-	-	-	-	-	-	-	3.5	5.5	6.7	9.2	11.6	12.9	15.4	16.4	17.0	21.8	24.3	25.4	28.4	30.2	30.2	34.5	34.5
Roadway Lighting	-	-	3.9	13.5	23.2	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	34.0	34.0
Sentinel Lighting	-	-	2.3	4.7	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	8.5	8.5
Infrared Heat Lamp	-	-	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.2	4.2
Commercial Showerhead	-	-	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.6	1.6
Commercial Air Barrier	-	-	-	-	-	-	-	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.7	0.7	0.7	0.8	0.8
Livestock Waterer	-	-	-	-	-	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-
Commercial Air Conditioning	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	2.9	4.8	5.2	5.2	-	-	-	-
	-	-	11.3	23.4	35.8	42.7	42.8	43.8	44.7	50.3	52.8	54.4	58.6	62.1	65.5	70.8	80.3	90.8	99.1	105.6	109.8	116.4	114.3	114.3	130.3	129.9
COMMERCIAL TOTAL	-	-	11.3	26.5	54.0	81.3	101.1	109.6	118.3	145.5	162.5	170.0	181.7	193.2	214.0	243.1	286.3	331.5	368.9	409.8	456.7	508.0	554.3	554.3	631.9	630.5
INDUSTRIAL																										
Performance Optimization	-	-	-	-	-	2.4	7.2	35.1	43.5	85.9	107.7	110.8	142.9	170.5	181.5	207.6	238.6	249.3	276.4	294.9	319.6	347.9	373.1	373.1	410.4	410.4
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	2.4	7.2	35.1	43.5	85.9	107.7	110.8	142.9	170.5	181.5	207.6	238.6	249.3	276.4	294.9	319.6	347.9	373.1	373.1	410.4	410.4
DISCONTINUED/COMPLETED																										
Retrofit/Demonstration GSL	-	-	-	0.1	0.7	9.7	32.7	32.7	32.7	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.0	33.0	33.0	33.0	33.0	33.0	36.3	36.3
High Efficiency Motors	-	-	0.4	4.8	7.7	10.3	13.3	17.9	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	23.6	23.6
Industrial (Basic)	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	0.4	4.9	8.3	20.0	46.0	50.6	54.2	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.5	54.5	54.5	54.5	54.5	54.5	59.9	59.9
INDUSTRIAL TOTAL	-	-	0.4	4.9	8.3	22.4	53.2	85.7	97.7	140.4	162.3	165.4	197.5	225.1	236.0	262.2	293.1	303.9	330.9	349.3	374.1	402.4	427.6	427.6	470.3	470.3
EFFICIENCY PROGRAMS SUBTOTAL	5.0	8.9	27.4	52.3	87.5	133.3	185.6	230.5	253.2	323.5	362.4	373.0	416.8	455.9	487.6	552.7	637.4	711.6	796.6	891.1	1,001.0	1,104.3	1,204.7	1,204.6	1,356.2	1,339.8
CUSTOMER SELF-GENERATION PROGRAMS																										
BioEnergy Optimization Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	120.1	84.2	94.0	80.1	86.6	70.3	0.1	0.1	0.1
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	120.1	84.2	94.0	80.1	86.6	70.3	0.1	0.1	0.1
RATE/LOAD MANAGEMENT PROGRAMS																										
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	5.0	8.9	27.4	52.3	87.5	133.3	185.6	230.5	253.2	323.5	362.4	373.0	416.8	455.9	487.6	552.7	647.6	831.6	880.8	985.1	1,081.1	1,190.8	1,274.9	1,204.7	N/A	N/A
GW.h IMPACTS (at generation)	5.7	10.2	31.2	59.4	99.4	151.1	209.5	259.3	284.7	363.1	406.6	418.6	467.2	510.7	546.5	619.6	726.2	931.1	987.5	1,105.3	1,214.2	1,338.0	1,433.5	1,356.2	1,356.2	1,339.9

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Persisting Energy Savings - GW.h
Electric Incentive Based Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Home Insulation	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7
Refrigerator Retirement Program	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	-	-	-	-	-
Water & Energy Saver	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Affordable Energy Program	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
	65.6	65.6	65.6	65.6	65.6	65.6	65.6	65.6	65.6	54.7	54.7	54.7	54.7	54.7
DISCONTINUED/COMPLETED														
Compact Fluorescent Lighting	92.1	65.7	65.7	45.9	18.9	89.4	89.4	89.4	89.4	89.4	89.9	89.9	89.9	89.9
Outdoor Timer	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5
Appliances	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
New Homes	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Energy Efficient Light Fixtures	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Seasonal LED Lighting	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
High Efficiency Furnace & Boiler	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Res Hot Water	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Water Heater Rental	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	157.2	130.8	130.8	111.0	84.0	154.5	154.5	154.5	154.5	154.5	155.0	155.0	155.0	155.0
RESIDENTIAL TOTAL	222.8	196.4	196.4	176.6	149.6	220.1	220.1	220.1	220.1	209.2	209.7	209.7	209.7	209.7
COMMERCIAL														
Commercial Lighting	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2
Internal Retrofit	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6
Commercial Earth Power	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Custom	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Commercial Insulation*	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Commercial Windows*	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
City of Winnipeg Agreement	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Commercial Refrigeration	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
HVAC - Chillers	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
New Buildings	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Commercial Building Optimization	0.9	0.9	0.9	0.9	0.9	0.9	0.9	-	-	-	-	-	-	-
Commercial Kitchen Appliances	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Commercial Clothes Washers	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Network Energy Manager	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	440.0	440.0	440.0	440.0	440.0	440.0	440.0	439.1	439.1	439.1	439.1	439.1	439.1	439.1
DISCONTINUED/COMPLETED														
Parking Lot Controllers	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4
Agricultural Heat Pads	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2
Roadway Lighting	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Sentinel Lighting	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Infrared Heat Lamp	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Showerhead	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial Air Barrier	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Power Smart Shops	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Livestock Waterer	0.4	0.2	0.1	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	114.3	114.2	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0
COMMERCIAL TOTAL	554.3	554.1	554.0	553.9	553.9	553.9	553.9	553.1	553.1	553.1	553.1	553.1	553.1	553.1
INDUSTRIAL														
Performance Optimization	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1
DISCONTINUED/COMPLETED														
Retrofit/Demonstration GSL	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
High Efficiency Motors	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
INDUSTRIAL TOTAL	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5
EFFICIENCY PROGRAMS SUBTOTAL	1,204.6	1,178.0	1,177.9	1,158.0	1,131.1	1,201.6	1,201.6	1,200.7	1,200.7	1,189.8	1,190.3	1,190.3	1,190.3	1,190.3
CUSTOMER SELF-GENERATION PROGRAMS														
BioEnergy Optimization Program	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
RATE/LOAD MANAGEMENT PROGRAMS														
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1,204.7	1,178.1	1,178.0	1,158.1	1,131.2	1,201.7	1,201.7	1,200.8	1,200.8	1,189.9	1,190.3	1,190.3	1,190.3	1,190.3
GW.h IMPACTS (at generation)	1,356.2	1,325.9	1,325.8	1,303.1	1,272.4	1,352.8	1,352.8	1,351.8	1,351.8	1,339.4	1,339.9	1,339.9	1,339.9	1,339.9

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-
Water & Energy Saver	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Affordable Energy Program	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7	54.7
DISCONTINUED/COMPLETED													
Compact Fluorescent Lighting	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9
Outdoor Timer	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5
Appliances	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
New Homes	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Energy Efficient Light Fixtures	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Seasonal LED Lighting	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
High Efficiency Furnace & Boiler	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Res Hot Water	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Water Heater Rental	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-
	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
RESIDENTIAL TOTAL	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7	209.7
COMMERCIAL													
Commercial Lighting	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2	281.2
Internal Retrofit	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6	53.6
Commercial Earth Power	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Custom	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Commercial Insulation*	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Commercial Windows*	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
City of Winnipeg Agreement	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Commercial Refrigeration	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
HVAC - Chillers	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
New Buildings	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Commercial Building Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Kitchen Appliances	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Commercial Clothes Washers	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Network Energy Manager	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1	439.1
DISCONTINUED/COMPLETED													
Parking Lot Controllers	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4
Agricultural Heat Pads	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2	30.2
Roadway Lighting	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Sentinel Lighting	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Infrared Heat Lamp	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Showerhead	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial Air Barrier	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Power Smart Shops	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-
	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0
COMMERCIAL TOTAL	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1	553.1
INDUSTRIAL													
Performance Optimization	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-
	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1	373.1
DISCONTINUED/COMPLETED													
Retrofit/Demonstration GSL	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
High Efficiency Motors	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-
	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
INDUSTRIAL TOTAL	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5	427.5
EFFICIENCY PROGRAMS SUBTOTAL	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3
CUSTOMER SELF-GENERATION PROGRAMS													
BioEnergy Optimization Program	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
RATE/LOAD MANAGEMENT PROGRAMS													
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3	1,190.3
GW.h IMPACTS (at generation)	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9	1,339.9

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Total Annual Energy Savings - GW.h
Electric Incentive Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Home Insulation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7	4.2	10.7	16.5	22.1	28.4	33.8	38.7	44.9	51.2	51.2
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	19.6	22.3	-
Water & Energy Saver	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.5	12.6	14.4	14.4
Affordable Energy Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.1	2.0	4.2	6.4	9.3	10.6	10.6
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7	4.2	10.7	17.0	23.2	30.4	38.0	65.6	86.3	98.4	76.1
DISCONTINUED/COMPLETED																										
Compact Fluorescent Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.1	15.4	20.6	28.1	49.9	77.7	92.1	92.1	92.1	105.0	102.5
Outdoor Timer	5.0	8.9	15.3	20.6	24.8	29.2	30.9	34.7	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	41.6	41.6
Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6	7.6	12.1	12.7	12.7	12.7	12.7	14.5	14.5
New Homes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.6	1.9	2.9	3.7	4.3	5.0	5.5	5.5	6.3	6.3
Energy Efficient Light Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	1.0	2.1	2.6	3.7	4.5	4.5	5.1	5.1
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	1.3	2.3	3.1	3.2	3.2	3.2	3.2	3.7	3.7
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.3	1.3	1.3	1.3	1.4	1.4
Res Hot Water	-	-	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Water Heater Rental	-	-	-	-	-	-	-	0.1	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	5.0	8.9	15.7	21.0	25.1	29.6	31.3	35.1	37.2	37.5	37.6	37.6	37.6	37.6	37.6	45.8	53.7	65.4	79.8	108.8	139.8	156.0	157.2	157.2	179.2	176.7
RESIDENTIAL TOTAL	5.0	8.9	15.7	21.0	25.1	29.6	31.3	35.1	37.2	37.5	37.6	37.6	37.6	37.6	37.6	47.5	57.9	76.1	96.9	132.0	170.2	193.9	222.8	243.5	277.6	252.9
COMMERCIAL																										
Commercial Lighting	-	-	-	2.9	17.0	35.9	55.0	61.2	67.4	85.4	90.8	94.9	100.2	105.6	116.2	132.6	153.1	175.8	193.9	218.9	239.5	258.7	281.2	309.0	352.2	352.2
Internal Retrofit	-	-	-	0.2	1.2	2.7	3.3	3.8	4.3	4.9	5.4	5.9	6.1	6.9	9.4	12.2	14.4	17.0	18.0	19.8	29.5	41.4	53.6	55.2	62.9	62.9
Commercial Earth Power	-	-	-	-	-	-	-	0.3	1.1	1.8	2.9	3.2	4.0	5.1	7.8	8.8	11.1	15.3	18.6	20.2	23.6	26.0	27.8	29.9	34.0	34.0
Commercial Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	3.0	4.3	5.5	7.0	8.7	21.2	24.2	24.2
Custom	-	-	-	-	-	-	-	0.4	0.4	2.6	10.0	10.8	11.7	12.2	12.8	12.8	12.9	13.1	15.4	15.9	17.4	18.8	20.2	21.0	23.9	23.9
Commercial Insulation*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.9	4.1	6.6	9.7	12.5	15.6	17.8	17.8
Commercial Windows*	-	-	-	-	-	-	-	0.1	0.4	0.6	0.7	0.9	1.0	1.4	1.8	2.3	3.2	3.9	4.5	5.2	7.3	9.7	11.7	13.9	15.8	15.8
City of Winnipeg Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.6	1.2	7.6	9.6	10.1	10.3	10.8	11.1	11.5	11.6	13.2	13.2
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.5	3.7	4.1	4.3	4.8	5.3	7.1	8.2	9.4	10.7	10.7
New Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	6.4	7.3	7.3
Commercial Building Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.6	0.9	0.9	1.0	1.1	-
Commercial Kitchen Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.5	0.6	0.7	0.7	0.8	0.8
Commercial Clothes Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.5	0.6	0.7	0.7
Network Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.1	0.1	0.2	0.2
	-	-	-	3.1	18.2	38.6	58.3	65.8	73.6	95.3	109.7	115.6	123.1	131.1	148.5	172.2	206.0	240.7	269.7	304.3	347.0	391.6	440.0	495.8	565.2	564.1
DISCONTINUED/COMPLETED																										
Parking Lot Controllers	-	-	-	-	-	-	-	0.8	1.6	3.7	4.1	4.4	5.9	6.8	8.8	11.5	20.0	27.9	30.5	32.4	34.9	38.1	39.4	39.4	44.9	44.9
Agricultural Heat Pads	-	-	-	-	-	-	-	-	-	3.5	5.5	6.7	9.2	11.6	12.9	15.4	16.4	17.0	21.8	24.3	25.4	28.4	30.2	32.0	36.5	36.5
Roadway Lighting	-	-	3.9	13.5	23.2	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	34.0	34.0
Sentinel Lighting	-	-	2.3	4.7	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	8.5	8.5
Infrared Heat Lamp	-	-	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.2	4.2
Commercial Showerhead	-	-	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.6	1.6
Commercial Air Barrier	-	-	-	-	-	-	-	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.7	0.7	0.7	0.8	0.8
Livestock Waterer	-	-	-	-	-	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-
Commercial Air Conditioning	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	2.9	4.8	5.2	5.2	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	11.3	23.4	35.8	42.7	42.8	43.8	44.7	50.3	52.8	54.4	58.6	62.1	65.5	70.8	80.3	90.8	99.1	105.6	109.8	116.4	114.3	116.1	132.4	132.0
COMMERCIAL TOTAL	-	-	11.3	26.5	54.0	81.3	101.1	109.6	118.3	145.5	162.5	170.0	181.7	193.2	214.0	243.1	286.3	331.5	368.9	409.8	456.7	508.0	554.3	611.9	697.6	696.0
INDUSTRIAL																										
Performance Optimization	-	-	-	-	-	2.4	7.2	35.1	43.5	85.9	107.7	110.8	142.9	170.5	181.5	207.6	238.6	249.3	276.4	294.9	319.6	347.9	373.1	441.8	486.0	486.0
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	2.4	7.2	35.1	43.5	85.9	107.7	110.8	142.9	170.5	181.5	207.6	238.6	249.3	276.4	294.9	319.6	347.9	373.1	441.8	486.0	486.0
DISCONTINUED/COMPLETED																										
Retrofit/Demonstration GSL	-	-	-	0.1	0.7	9.7	32.7	32.7	32.7	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.1	33.0	33.0	33.0	33.0	33.0	33.0	36.3	36.3
High Efficiency Motors	-	-	0.4	4.8	7.7	10.3	13.3	17.9	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	23.6	23.6
Industrial (Basic)	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	0.4	4.9	8.3	20.0	46.0	50.6	54.2	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.5	54.5	54.5	54.5	54.5	54.5	59.9	59.9
INDUSTRIAL TOTAL	-	-	0.4	4.9	8.3	22.4	53.2	85.7	97.7	140.4	162.3	165.4	197.5	225.1	236.0	262.2	293.1	303.9	330.9	349.3	374.1	402.4	427.6	496.3	545.9	545.9
EFFICIENCY PROGRAMS SUBTOTAL	5.0	8.9	27.4	52.3	87.5	133.3	185.6	230.5	253.2	323.5	362.4	373.0	416.8	455.9	487.6	552.7	637.4	711.6	796.6	891.1	1,001.0	1,104.3	1,204.7	1,351.7	1,521.1	1,494.8
CUSTOMER SELF-GENERATION PROGRAMS																										
Bioenergy Optimization Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	120.1	84.2	94.0	80.1	86.6	70.3	82.5	90.8	55.7
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	120.1	84.2	94.0	80.1	86.6	70.3	82.5	80.1	57.8
RATE/LOAD MANAGEMENT PROGRAMS																										
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	5.0	8.9	27.4	52.3	87.5	133.3	185.6	230.5	253.2	323.5	362.4	373.0	416.8	455.9	487.6	552.7	647.6	831.6	880.8	985.1	1,081.1	1,190.8	1,274.9	1,434.3	N/A	N/A
GW.h IMPACTS (at generation)	5.7	10.2	31.2	59.4	99.4	151.1	209.5	259.3	284.7	363.1	406.6	418.6	467.2	510.7	546.5	619.6	726.2	931.1	987.5	1,105.3	1,214.2	1,338.0	1,433.5	1,611.9	1,611.9	1,550.5

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Total Annual Energy Savings - GW.h
Electric Incentive Based Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Home Insulation	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9
Refrigerator Retirement Program	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	8.6	-	-	-	-
Water & Energy Saver	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Affordable Energy Program	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	75.4	66.8	66.8	66.8	66.8
DISCONTINUED/COMPLETED														
Compact Fluorescent Lighting	92.1	65.7	65.7	45.9	18.9	89.4	89.4	89.4	89.4	89.4	89.9	89.9	89.9	89.9
Outdoor Timer	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5
Appliances	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
New Homes	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Energy Efficient Light Fixtures	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Seasonal LED Lighting	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
High Efficiency Furnace & Boiler	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Res Hot Water	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Water Heater Rental	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	157.2	130.8	130.8	111.0	84.1	154.6	154.6	154.6	154.6	154.6	155.0	155.0	155.0	155.0
RESIDENTIAL TOTAL	243.5	217.1	217.1	197.3	170.4	240.9	240.9	240.9	240.9	230.0	221.8	221.8	221.8	221.8
COMMERCIAL														
Commercial Lighting	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0
Internal Retrofit	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2
Commercial Earth Power	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Commercial Refrigeration	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2
Custom	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Commercial Insulation*	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Commercial Windows*	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
City of Winnipeg Agreement	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
HVAC - Chillers	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
New Buildings	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Commercial Building Optimization	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.1	0.1	-	-	-	-	-
Commercial Kitchen Appliances	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Commercial Clothes Washers	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Network Energy Manager	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	495.8	495.8	495.8	495.8	495.8	495.8	495.8	494.9	494.9	494.8	494.8	494.8	494.8	494.8
DISCONTINUED/COMPLETED														
Parking Lot Controllers	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4
Agricultural Heat Pads	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Roadway Lighting	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Sentinel Lighting	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Infrared Heat Lamp	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Showerhead	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial Air Barrier	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Power Smart Shops	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Livestock Waterer	0.4	0.2	0.1	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	116.1	116.0	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8
COMMERCIAL TOTAL	611.9	611.7	611.6	611.5	611.5	611.5	611.5	610.6	610.6	610.5	610.5	610.5	610.5	610.5
INDUSTRIAL														
Performance Optimization	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8
DISCONTINUED/COMPLETED														
Retrofit/Demonstration GSL	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
High Efficiency Motors	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
INDUSTRIAL TOTAL	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3
EFFICIENCY PROGRAMS SUBTOTAL	1,351.7	1,325.1	1,325.0	1,305.1	1,278.2	1,348.7	1,348.7	1,347.8	1,347.8	1,336.8	1,328.6	1,328.6	1,328.6	1,328.6
CUSTOMER SELF-GENERATION PROGRAMS														
Bioenergy Optimization Program	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7
	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7
RATE/LOAD MANAGEMENT PROGRAMS														
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1,402.4	1,375.8	1,375.7	1,355.8	1,328.9	1,399.4	1,399.4	1,398.5	1,398.5	1,387.5	1,379.3	1,379.3	1,379.3	1,379.3
GW.h IMPACTS (at generation)	1,576.9	1,546.6	1,546.4	1,523.8	1,493.0	1,573.4	1,573.4	1,572.4	1,572.4	1,559.9	1,550.5	1,550.5	1,550.5	1,550.5

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9	44.9
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-
Water & Energy Saver	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Affordable Energy Program	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8	66.8
DISCONTINUED/COMPLETED													
Compact Fluorescent Lighting	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9
Outdoor Timer	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5	36.5
Appliances	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
New Homes	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Energy Efficient Light Fixtures	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Seasonal LED Lighting	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
High Efficiency Furnace & Boiler	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Res Hot Water	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Water Heater Rental	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Thermostat	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-
	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0
RESIDENTIAL TOTAL	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8	221.8
COMMERCIAL													
Commercial Lighting	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0
Internal Retrofit	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2
Commercial Earth Power	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Commercial Refrigeration	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2
Custom	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Commercial Insulation*	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Commercial Windows*	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
City of Winnipeg Agreement	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
HVAC - Chillers	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
New Buildings	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Commercial Building Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Kitchen Appliances	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Commercial Clothes Washers	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Network Energy Manager	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HVAC - CO2 Sensors	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8	494.8
DISCONTINUED/COMPLETED													
Parking Lot Controllers	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4
Agricultural Heat Pads	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Roadway Lighting	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9
Sentinel Lighting	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Infrared Heat Lamp	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Showerhead	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial Air Barrier	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Power Smart Shops	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
Spray Valves	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-
	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8	115.8
COMMERCIAL TOTAL	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5	610.5
INDUSTRIAL													
Performance Optimization	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-
	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8	441.8
DISCONTINUED/COMPLETED													
Retrofit/Demonstration GSL	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
High Efficiency Motors	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-
	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5	54.5
INDUSTRIAL TOTAL	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3	496.3
EFFICIENCY PROGRAMS SUBTOTAL	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6	1,328.6
CUSTOMER SELF-GENERATION PROGRAMS													
Bioenergy Optimization Program	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7
	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7
RATE/LOAD MANAGEMENT PROGRAMS													
Curtailable Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3	1,379.3
GW.h IMPACTS (at generation)	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5	1,550.5

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Appendix G

Average Winter Demand Savings - Incentive-Based Programs

2012/13 Average Winter MW
Electric Incentive Based Programs

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																	
Home Insulation	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.8	3.8
Affordable Energy Program	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.3	1.3
Refrigerator Retirement Program	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	-	-	-	1.1	-
WESP	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.0	5.0	5.0	5.0	6.8	5.7
DISCONTINUED/COMPLETED																	
New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CFL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Residential Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Outdoor Timer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Res Hot Water	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heater Rental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EELF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retrofit/Demonstration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RESIDENTIAL TOTAL	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.0	5.0	5.0	5.0	6.8	5.7
COMMERCIAL																	
Commercial Lighting Program	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	8.7	8.7
Commercial Refrigeration	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.6	1.6
Commercial Insulation*	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.4	1.4
Commercial New Buildings	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2
Commercial Windows*	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	1.0	1.0
Commercial Earth Power	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Internal Retrofit	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial Washers	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
City of Winnipeg Agreement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - CO2 Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CBOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	0.0	-
Commercial Kitchen Appliances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Custom Measures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	15.0	14.9
DISCONTINUED/COMPLETED																	
Agricultural Heat Pads	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Showerhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Infrared Heat Lamp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Roadway Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sentinel Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Barrier	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agricultural Demand Controller	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
COMMERCIAL TOTAL	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	15.2	15.2
INDUSTRIAL																	
Performance Optimization	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	9.5	9.5
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	9.5	9.5
DISCONTINUED/COMPLETED																	
Industrial (Basic)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retrofit/Demonstration GSL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High Efficiency Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
INDUSTRIAL TOTAL	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	9.5	9.5
EFFICIENCY PROGRAMS SUBTOTAL	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	27.0	27.0	27.0	27.0	31.5	30.4
CUSTOMER SELF-GENERATION PROGRAMS																	
Bioenergy	9.4	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	10.3	6.3
	9.4	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	10.3	6.3
RATE/LOAD MANAGEMENT PROGRAMS																	
Industrial Curtailable Rate	144.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	159.2	-
	144.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	159.2	-
MW IMPACTS (at meter)	182.1	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	32.8	32.8	32.8	32.8	N/A	N/A
MW IMPACTS (at generation)	201.1	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	36.8	36.8	36.8	36.8	201.1	36.8

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Persisting Average Winter MW
Electric Incentive Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Home Insulation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	2.0	5.2	8.0	10.7	13.8	16.4	18.8	18.8	21.4	21.4
Affordable Energy Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.7	1.5	3.0	3.0	3.5	3.5
WESP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7	1.3	1.3	1.5	1.5
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7	0.7	0.8	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	2.0	5.2	8.1	11.0	14.5	18.6	23.9	23.9	27.2	26.4
DISCONTINUED/COMPLETED																										
CFL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6	3.1	4.2	5.7	10.2	17.7	21.3	21.3	21.3	24.3	23.9
Outdoor Timer	0.3	0.5	0.9	1.2	1.5	1.9	2.0	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.7	2.7
Residential Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	1.0	1.6	1.7	1.7	1.7	1.7	1.9	1.9
New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.4	0.7	1.0	1.2	1.5	1.6	1.6	1.8	1.8
EELF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.3	0.4	0.6	0.7	0.7	0.8	0.8
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4	0.4	0.4	0.5	0.5
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.3	0.5	1.0	1.3	1.6	1.9	2.1	2.4	2.5	2.5	2.6	2.6	2.6	2.6	2.5	4.2	5.9	7.8	10.3	15.8	24.2	28.2	28.6	28.6	32.6	32.1
RESIDENTIAL TOTAL	0.3	0.5	1.0	1.3	1.6	1.9	2.1	2.4	2.5	2.5	2.6	2.6	2.6	2.6	2.5	5.0	7.9	12.9	18.4	26.8	38.7	46.9	52.4	52.4	59.8	58.6
COMMERCIAL																										
Commercial Lighting Program	-	-	-	0.5	2.6	5.7	9.2	10.8	11.6	15.1	16.4	17.4	18.5	19.7	21.7	24.2	27.7	31.1	34.1	38.5	42.3	45.7	48.8	48.8	55.6	55.6
Commercial Earth Power	-	-	-	-	-	-	-	0.1	0.8	1.1	1.5	1.7	2.0	2.4	3.8	4.2	5.4	7.4	8.7	9.3	10.3	11.2	11.9	11.9	13.6	13.6
Internal Retrofit	-	-	-	0.0	0.3	0.6	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4	1.7	2.2	2.4	2.8	3.0	3.2	5.4	8.3	11.7	11.7	13.3	13.3
Commercial Insulation*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.7	1.8	3.2	4.8	6.2	6.2	7.1	7.1
Commercial Windows*	-	-	-	-	-	-	-	0.1	0.2	0.3	0.3	0.4	0.5	0.6	0.8	1.1	1.5	1.7	1.8	2.1	3.0	4.0	4.8	4.8	5.5	5.5
City of Winnipeg Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.1	0.3	1.6	2.0	2.1	2.2	2.4	2.5	2.6	2.6	2.9	2.9
Commercial Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.8	1.3	1.6	1.9	2.1	2.1	2.4	2.4
Commercial Custom Measures	-	-	-	-	-	-	-	0.0	0.0	0.1	0.4	0.5	0.5	0.5	0.9	0.9	0.9	1.0	1.1	1.2	1.2	1.4	1.7	1.7	1.9	1.9
Commercial New Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4	0.5	0.5
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.3	0.4	0.4	0.4	0.4
Commercial Kitchen Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-	-	-	0.0	0.1	0.1	0.2	0.2	0.2	0.2
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	-
Network Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	0.5	2.9	6.3	9.8	11.8	13.5	17.6	19.7	21.1	22.7	24.6	29.0	32.8	39.4	46.3	52.4	59.8	69.7	80.4	90.8	90.8	103.5	103.5
DISCONTINUED/COMPLETED																										
Roadway Lighting	-	-	0.9	3.1	5.4	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.9	7.9
Agricultural Heat Pads	-	-	-	-	-	-	-	-	-	0.7	1.0	1.2	1.6	2.0	2.2	2.6	2.7	2.8	3.2	3.5	3.6	3.9	4.1	4.1	4.6	4.6
Sentinel Lighting	-	-	0.5	1.1	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.0
Agricultural Demand Controller	-	-	-	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1
Infrared Heat Lamp	-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Commercial Air Barrier	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.2
Livestock Waterer	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.3	0.3	-	-	-	-
	-	-	2.2	5.7	9.0	10.6	10.7	10.8	10.8	11.4	11.8	12.0	12.5	12.9	13.2	13.6	13.7	13.7	14.2	14.7	14.9	15.2	15.1	15.1	17.3	17.2
COMMERCIAL TOTAL	-	-	2.2	6.3	11.9	16.9	20.5	22.5	24.2	29.1	31.5	33.2	35.2	37.5	42.1	46.4	53.1	60.1	66.6	74.5	84.6	95.6	105.9	105.9	120.8	120.6
INDUSTRIAL																										
Performance Optimization	-	-	-	-	-	0.3	1.1	4.6	5.8	37.4	39.1	39.5	48.4	52.9	54.1	57.6	61.7	63.2	66.2	68.7	72.0	75.5	78.9	78.9	86.8	86.8
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	0.3	1.1	4.6	5.8	37.4	39.1	39.5	48.4	52.9	54.1	57.6	61.7	63.2	66.2	68.7	72.0	75.5	78.9	78.9	86.8	86.8
DISCONTINUED/COMPLETED																										
Retrofit/Demonstration GSL	-	-	-	0.3	0.4	1.6	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.8	4.8
High Efficiency Motors	-	-	0.1	0.7	1.3	1.8	2.3	3.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.2	4.2
Industrial (Basic)	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	0.1	1.0	1.7	3.4	6.6	7.4	8.1	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	9.0	9.0
INDUSTRIAL TOTAL	-	-	0.1	1.0	1.7	3.7	7.7	12.0	13.9	45.5	47.3	47.6	56.6	61.1	62.2	65.8	69.8	71.3	74.4	76.9	80.2	83.7	87.1	87.1	95.8	95.8
EFFICIENCY PROGRAMS SUBTOTAL	0.3	0.5	3.3	8.6	15.2	22.6	30.3	36.9	40.6	77.1	81.4	83.4	94.4	101.2	106.9	117.2	130.9	144.3	159.4	178.1	203.4	226.1	245.5	245.5	276.3	275.0
CUSTOMER SELF-GENERATION PROGRAMS																										
Bioenergy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.3	14.3	14.3	14.3	14.3	14.3	14.4	0.0	0.1	0.1
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.3	14.3	14.3	14.3	14.3	14.3	14.4	0.0	0.1	0.1
RATE/LOAD MANAGEMENT PROGRAMS																										
Industrial Curtailable Rate	-	-	-	-	40.7	46.4	24.7	32.7	80.0	48.2	58.0	57.1	68.0	110.3	148.5	153.8	189.1	183.3	180.6	172.8	149.2	154.5	147.2	-	-	-
	-	-	-	-	40.7	46.4	24.7	32.7	80.0	48.2	58.0	57.1	68.0	110.3	148.5	153.8	189.1	183.3	180.6	172.8	149.2	154.5	147.2	-	-	-
MW IMPACTS (at meter)	0.3	0.5	3.3	8.6	55.9	69.0	55.0	69.6	120.6	125.3	139.4	140.5	162.4	211.4	255.4	270.9	334.2	341.9	354.3	365.2	366.9	395.0	407.1	245.5	N/A	N/A
MW IMPACTS (at generation)	0.3	0.6	3.7	9.8	62.1	76.6	61.4	77.5	133.8	139.1	154.6	155.9	180.1	234.2	282.7	300.1	370.1	379.1	393.2	405.8	408.5	440.2	454.1	276.4	276.4	275.0

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Persisting Average Winter MW
Electric Incentive Based Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Home Insulation	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Affordable Energy Program	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
WESP	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Refrigerator Retirement Program	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	-	-	-	-	-
	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.9	23.2	23.2	23.2	23.2	23.2
DISCONTINUED/COMPLETED														
CFL	21.3	16.9	16.9	13.5	9.0	20.9	20.9	20.9	20.9	20.9	21.0	21.0	21.0	21.0
Outdoor Timer	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Residential Appliances	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
New Home Program	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EELF	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
High Efficiency Furnace & Boiler	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Seasonal LED Lighting	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	28.6	24.1	24.1	20.7	16.2	28.1	28.1	28.1	28.1	28.1	28.2	28.2	28.2	28.2
RESIDENTIAL TOTAL	52.4	48.0	48.0	44.6	40.1	52.0	52.0	52.0	52.0	51.3	51.4	51.4	51.4	51.4
COMMERCIAL														
Commercial Lighting Program	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8
Commercial Earth Power	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Internal Retrofit	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Commercial Insulation*	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Commercial Windows*	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
City of Winnipeg Agreement	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Commercial Refrigeration	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Commercial Custom Measures	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial New Buildings	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Washers	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Kitchen Appliances	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CBOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	90.8	90.8	90.8	90.8	90.8	90.8	90.8	90.7	90.7	90.7	90.7	90.7	90.7	90.7
DISCONTINUED/COMPLETED														
Roadway Lighting	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Agricultural Heat Pads	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Sentinel Lighting	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Agricultural Demand Controller	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Infrared Heat Lamp	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Commercial Air Barrier	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Livestock Waterer	0.1	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15.1	15.1	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
COMMERCIAL TOTAL	105.9	105.9	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8
INDUSTRIAL														
Performance Optimization	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9
DISCONTINUED/COMPLETED														
Retrofit/Demonstration GSL	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
High Efficiency Motors	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
INDUSTRIAL TOTAL	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1
EFFICIENCY PROGRAMS SUBTOTAL	245.5	240.9	240.9	237.5	233.0	244.9	244.9	244.9	244.9	244.2	244.3	244.3	244.3	244.3
CUSTOMER SELF-GENERATION PROGRAMS														
Bioenergy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE/LOAD MANAGEMENT PROGRAMS														
Industrial Curtailable Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MW IMPACTS (at meter)	245.5	241.0	241.0	237.6	233.0	245.0	245.0	244.9	244.9	244.2	244.3	244.3	244.3	244.3
MW IMPACTS (at generation)	276.4	271.2	271.2	267.4	262.2	275.8	275.8	275.7	275.7	274.9	275.0	275.0	275.0	275.0

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Affordable Energy Program	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
WESP	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-
	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
DISCONTINUED/COMPLETED													
CFL	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Outdoor Timer	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Residential Appliances	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
New Home Program	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EELF	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
High Efficiency Furnace & Boiler	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Seasonal LED Lighting	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-
	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
RESIDENTIAL TOTAL	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
COMMERCIAL													
Commercial Lighting Program	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8	48.8
Commercial Earth Power	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Internal Retrofit	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Commercial Insulation*	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Commercial Windows*	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
City of Winnipeg Agreement	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Commercial Refrigeration	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Commercial Custom Measures	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial New Buildings	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Washers	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Kitchen Appliances	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-
	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7	90.7
DISCONTINUED/COMPLETED													
Roadway Lighting	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Agricultural Heat Pads	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Sentinel Lighting	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Agricultural Demand Controller	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Infrared Heat Lamp	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Commercial Air Barrier	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-
	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
COMMERCIAL TOTAL	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8	105.8
INDUSTRIAL													
Performance Optimization	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-
	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9	78.9
DISCONTINUED/COMPLETED													
Retrofit/Demonstration GSL	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
High Efficiency Motors	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
INDUSTRIAL TOTAL	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1	87.1
EFFICIENCY PROGRAMS SUBTOTAL	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3
CUSTOMER SELF-GENERATION PROGRAMS													
Bioenergy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE/LOAD MANAGEMENT PROGRAMS													
Industrial Curtailable Rate	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
MW IMPACTS (at meter)	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3
MW IMPACTS (at generation)	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Total Average Winter MW
Electric Incentive Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Home Insulation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	2.0	5.2	8.0	10.7	13.8	16.4	18.8	22.1	25.2	25.2
Affordable Energy Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.4	0.7	1.5	3.0	4.1	4.7	4.7
WESP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7	1.3	2.0	2.2	2.2
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7	1.7	1.9	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	2.0	5.2	8.1	11.0	14.5	18.6	23.9	29.9	34.0	32.1
DISCONTINUED/COMPLETED																										
CFL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6	3.1	4.2	5.7	10.2	17.7	21.3	21.3	21.3	24.3	23.9
Outdoor Timer	0.3	0.5	0.9	1.2	1.5	1.9	2.0	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.7	2.7
Residential Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5	1.0	1.6	1.7	1.7	1.7	1.7	1.9	1.9
New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.4	0.7	1.0	1.2	1.5	1.6	1.6	1.9	1.9
EELF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.3	0.4	0.6	0.7	0.7	0.8	0.8
High Efficiency Furnace & Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4	0.4	0.4	0.5	0.5
Seasonal LED Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.3	0.5	1.0	1.3	1.6	1.9	2.1	2.4	2.5	2.5	2.6	2.6	2.6	2.6	2.5	4.2	5.9	7.8	10.3	15.8	24.2	28.2	28.6	28.6	32.6	32.1
RESIDENTIAL TOTAL	0.3	0.5	1.0	1.3	1.6	1.9	2.1	2.4	2.5	2.5	2.6	2.6	2.6	2.6	2.5	5.0	7.9	12.9	18.4	26.8	38.7	46.9	52.4	58.4	66.6	64.3
COMMERCIAL																										
Commercial Lighting Program	-	-	-	0.5	2.6	5.7	9.2	10.8	11.6	15.1	16.4	17.4	18.5	19.7	21.7	24.2	27.7	31.1	34.1	38.5	42.3	45.7	48.8	56.5	64.4	64.4
Commercial Earth Power	-	-	-	-	-	-	-	0.1	0.8	1.1	1.5	1.7	2.0	2.4	3.8	4.2	5.4	7.4	8.7	9.3	10.3	11.2	11.9	12.4	14.2	14.2
Internal Retrofit	-	-	-	0.0	0.3	0.6	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4	1.7	2.2	2.4	2.8	3.0	3.2	5.4	8.3	11.7	11.9	13.6	13.6
Commercial Insulation*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.7	1.8	3.2	4.8	6.2	7.4	8.5	8.5
Commercial Windows*	-	-	-	-	-	-	-	0.1	0.2	0.3	0.3	0.4	0.5	0.6	0.8	1.1	1.5	1.7	1.8	2.1	3.0	4.0	4.8	5.6	6.4	6.4
Commercial Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.8	1.3	1.6	1.9	2.1	3.5	4.0	4.0
City of Winnipeg Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.1	0.3	1.6	2.0	2.1	2.2	2.4	2.5	2.6	2.6	3.0	3.0
Commercial Custom Measures	-	-	-	-	-	-	-	0.0	0.0	0.1	0.4	0.5	0.5	0.5	0.9	0.9	0.9	1.0	1.1	1.2	1.2	1.4	1.7	1.7	1.9	1.9
Commercial New Buildings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	1.5	1.7	1.7
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.2	0.3	0.4	0.4	0.5	0.5
Commercial Kitchen Appliances	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	-	-	-	-	-	0.0	0.1	0.1	0.2	0.2	0.2	0.2
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	-
HVAC - CO2 Sensors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Network Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	0.5	2.9	6.3	9.8	11.8	13.5	17.6	19.7	21.1	22.7	24.6	29.0	32.8	39.4	46.3	52.4	59.8	69.7	80.4	90.8	103.9	118.4	118.4
DISCONTINUED/COMPLETED																										
Roadway Lighting	-	-	0.9	3.1	5.4	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.9	7.9
Agricultural Heat Pads	-	-	-	-	-	-	-	-	-	0.7	1.0	1.2	1.6	2.0	2.2	2.6	2.7	2.8	3.2	3.5	3.6	3.9	4.1	4.3	4.9	4.9
Sentinel Lighting	-	-	0.5	1.1	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	2.0	2.0
Agricultural Demand Controller	-	-	-	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1
Infrared Heat Lamp	-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Commercial Air Barrier	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.2
Livestock Waterer	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	0.3	0.3	-	-	-	-
	-	-	2.2	5.7	9.0	10.6	10.7	10.8	10.8	11.4	11.8	12.0	12.5	12.9	13.2	13.6	13.7	13.7	14.2	14.7	14.9	15.2	15.1	15.4	17.5	17.4
COMMERCIAL TOTAL	-	-	2.2	6.3	11.9	16.9	20.5	22.5	24.2	29.1	31.5	33.2	35.2	37.5	42.1	46.4	53.1	60.1	66.6	74.5	84.6	95.6	105.9	119.3	136.0	135.8
INDUSTRIAL																										
Performance Optimization	-	-	-	-	-	0.3	1.1	4.6	5.8	37.4	39.1	39.5	48.4	52.9	54.1	57.6	61.7	63.2	66.2	68.7	72.0	75.5	78.9	87.6	96.3	96.3
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	0.3	1.1	4.6	5.8	37.4	39.1	39.5	48.4	52.9	54.1	57.6	61.7	63.2	66.2	68.7	72.0	75.5	78.9	87.6	96.3	96.3
DISCONTINUED/COMPLETED																										
Retrofit/Demonstration GSL	-	-	-	0.3	0.4	1.6	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.8	4.8
High Efficiency Motors	-	-	0.1	0.7	1.3	1.8	2.3	3.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.2	4.2
Industrial (Basic)	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	0.1	1.0	1.7	3.4	6.6	7.4	8.1	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	9.0	9.0
INDUSTRIAL TOTAL	-	-	0.1	1.0	1.7	3.7	7.7	12.0	13.9	45.5	47.3	47.6	56.6	61.1	62.2	65.8	69.8	71.3	74.4	76.9	80.2	83.7	87.1	95.7	105.3	105.3
EFFICIENCY PROGRAMS SUBTOTAL	0.3	0.5	3.3	8.6	15.2	22.6	30.3	36.9	40.6	77.1	81.4	83.4	94.4	101.2	106.9	117.2	130.9	144.3	159.4	178.1	203.4	226.1	245.5	273.4	307.9	305.4
CUSTOMER SELF-GENERATION PROGRAMS																										
Bioenergy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.3	14.3	14.3	14.3	14.3	14.3	14.4	9.4	10.4	6.4
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.3	14.3	14.3	14.3	14.3	14.3	14.4	9.4	10.4	6.4
RATE/LOAD MANAGEMENT PROGRAMS																										
Industrial Curtailable Rate	-	-	-	-	40.7	46.4	24.7	32.7	80.0	48.2	58.0	57.1	68.0	110.3	148.5	153.8	189.1	183.3	180.6	172.8	149.2	154.5	147.2	144.8	159.2	-
	-	-	-	-	40.7	46.4	24.7	32.7	80.0	48.2	58.0	57.1	68.0	110.3	148.5	153.8	189.1	183.3	180.6	172.8	149.2	154.5	147.2	144.8	159.2	-
MW IMPACTS (at meter)	0.3	0.5	3.3	8.6	55.9	69.0	55.0	69.6	120.6	125.3	139.4	140.5	162.4	211.4	255.4	270.9	334.2	341.9	354.3	365.2	366.9	395.0	407.1	427.6	N/A	N/A
MW IMPACTS (at generation)	0.3	0.6	3.7	9.8	62.1	76.6	61.4	77.5	133.8	139.1	154.6	155.9	180.1	234.2	282.7	300.1	370.1	379.1	393.2	405.8	408.5	440.2	454.1	477.5	477.5	311.8

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Total Average Winter MW
Electric Incentive Based Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Home Insulation	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Affordable Energy Program	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
WESP	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Refrigerator Retirement Program	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.0	-	-	-	-
	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.9	29.2	28.2	28.2	28.2	28.2
DISCONTINUED/COMPLETED														
CFL	21.3	16.9	16.9	13.5	9.0	20.9	20.9	20.9	20.9	20.9	21.0	21.0	21.0	21.0
Outdoor Timer	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Residential Appliances	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
New Home Program	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EELF	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
High Efficiency Furnace & Boiler	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Seasonal LED Lighting	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	28.6	24.1	24.1	20.8	16.2	28.1	28.1	28.1	28.1	28.1	28.2	28.2	28.2	28.2
RESIDENTIAL TOTAL	58.4	54.0	54.0	50.6	46.0	58.0	58.0	58.0	58.0	57.3	56.4	56.4	56.4	56.4
COMMERCIAL														
Commercial Lighting Program	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5
Commercial Earth Power	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Internal Retrofit	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Commercial Insulation*	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Commercial Windows*	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Commercial Refrigeration	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
City of Winnipeg Agreement	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Commercial Custom Measures	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial New Buildings	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial Washers	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Kitchen Appliances	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CBOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-
HVAC - CO2 Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9
DISCONTINUED/COMPLETED														
Roadway Lighting	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Agricultural Heat Pads	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Sentinel Lighting	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Agricultural Demand Controller	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Infrared Heat Lamp	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Commercial Air Barrier	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Livestock Waterer	0.1	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15.4	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
COMMERCIAL TOTAL	119.3	119.2	119.2	119.2	119.2	119.2	119.2	119.1	119.1	119.1	119.1	119.1	119.1	119.1
INDUSTRIAL														
Performance Optimization	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
DISCONTINUED/COMPLETED														
Retrofit/Demonstration GSL	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
High Efficiency Motors	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
INDUSTRIAL TOTAL	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7
EFFICIENCY PROGRAMS SUBTOTAL	273.4	268.9	268.9	265.5	261.0	272.9	272.9	272.8	272.8	272.1	271.3	271.3	271.3	271.3
CUSTOMER SELF-GENERATION PROGRAMS														
Bioenergy	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
RATE/LOAD MANAGEMENT PROGRAMS														
Industrial Curtailable Rate	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MW IMPACTS (at meter)	279.2	274.7	274.7	271.3	266.8	278.7	278.7	278.7	278.7	278.0	277.1	277.1	277.1	277.1
MW IMPACTS (at generation)	314.3	309.1	309.1	305.3	300.1	313.7	313.7	313.6	313.6	312.8	311.8	311.8	311.8	311.8

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1
Affordable Energy Program	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
WESP	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Refrigerator Retirement Program	-	-	-	-	-	-	-	-	-	-	-	-	-
	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
DISCONTINUED/COMPLETED													
CFL	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Outdoor Timer	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Residential Appliances	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
New Home Program	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
EELF	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
High Efficiency Furnace & Boiler	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Seasonal LED Lighting	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Res Hot Water	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Water Heater Rental	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retrofit/Demonstration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-
RBB	-	-	-	-	-	-	-	-	-	-	-	-	-
	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
RESIDENTIAL TOTAL	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4
COMMERCIAL													
Commercial Lighting Program	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5
Commercial Earth Power	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Internal Retrofit	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Commercial Insulation*	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Commercial Windows*	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Commercial Refrigeration	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
City of Winnipeg Agreement	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Commercial Custom Measures	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial New Buildings	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial Washers	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Kitchen Appliances	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC - CO2 Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Network Energy Manager	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HVAC - Chillers	-	-	-	-	-	-	-	-	-	-	-	-	-
	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9	103.9
DISCONTINUED/COMPLETED													
Roadway Lighting	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Agricultural Heat Pads	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Sentinel Lighting	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Agricultural Demand Controller	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Infrared Heat Lamp	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Commercial Air Barrier	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Showerhead	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Power Smart Shops	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Livestock Waterer	-	-	-	-	-	-	-	-	-	-	-	-	-
PS Energy Manager	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Air Conditioning	-	-	-	-	-	-	-	-	-	-	-	-	-
Aboriginal Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
PLC	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-
	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
COMMERCIAL TOTAL	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1	119.1
INDUSTRIAL													
Performance Optimization	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
Emergency Preparedness	-	-	-	-	-	-	-	-	-	-	-	-	-
	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
DISCONTINUED/COMPLETED													
Retrofit/Demonstration GSL	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
High Efficiency Motors	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Industrial (Basic)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Efficient Motors (QMR)	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
INDUSTRIAL TOTAL	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7
EFFICIENCY PROGRAMS SUBTOTAL	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3	271.3
CUSTOMER SELF-GENERATION PROGRAMS													
Bioenergy	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
RATE/LOAD MANAGEMENT PROGRAMS													
Industrial Curtailable Rate	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
MW IMPACTS (at meter)	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1	277.1
MW IMPACTS (at generation)	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8	311.8

Note: Subtotals may not be exact due to rounding.
* Programs comprise the Commercial Building Envelope Program.

Appendix H

Natural Gas Savings (m^3) - Incentive-Based Programs

2012/13 Annual Gas Savings - million m^3
Natural Gas Incentive Based Programs

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
RESIDENTIAL														
Home Insulation	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Affordable Energy Program	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Water & Energy Saver	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
DISCONTINUED/COMPLETED														
New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Res HE Gas Furnace - Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RESIDENTIAL TOTAL	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
COMMERCIAL														
Commercial New Buildings	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
HVAC	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Commercial Custom Measures	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Commercial Insulation*	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Commercial Windows*	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CBOP	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-	-	-	-
Commercial Kitchen Appliances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
City of Winnipg Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.0	6.0	6.0	6.0
DISCONTINUED/COMPLETED														
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COMMERCIAL TOTAL	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.0	6.0	6.0	6.0
INDUSTRIAL														
Industrial Natural Gas Optimization	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
INDUSTRIAL TOTAL	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
EFFICIENCY PROGRAMS SUBTOTAL	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.2	11.2	11.2	11.2
CUSTOMER SELF-GENERATION														
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(0.7)	(0.8)	(0.8)	(0.9)	(0.8)	(0.8)	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(0.2)	(0.2)	(0.2)
NET IMPACT: OVERALL	10.6	10.5	10.5	10.5	10.5	10.6	10.4	10.4	10.4	10.4	10.3	11.0	11.0	11.0

	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL														
Home Insulation	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Affordable Energy Program	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Water & Energy Saver	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
DISCONTINUED/COMPLETED														
New Home Program	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Res HE Gas Furnace - Boiler	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RESIDENTIAL TOTAL	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
COMMERCIAL														
Commercial New Buildings	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
HVAC	1.3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Commercial Custom Measures	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Commercial Insulation*	1.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Commercial Windows*	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-
CBOP	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial Kitchen Appliances	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
City of Winnipg Agreement	-	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
DISCONTINUED/COMPLETED														
Power Smart Shops	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COMMERCIAL TOTAL	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
INDUSTRIAL														
Industrial Natural Gas Optimization	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
INDUSTRIAL TOTAL	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
EFFICIENCY PROGRAMS SUBTOTAL	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
CUSTOMER SELF-GENERATION														
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
NET IMPACT: OVERALL	11.1	11.1	11.1	11.0	11.0	11.0	11.0	11.0	10.9	10.9	10.9	10.9	10.9	10.9

Note: Subtotals may not be exact due to rounding.
* Programs comprise Commercial Building Envelope Program.

Persisting Gas Savings - million m3
Natural Gas Incentive Based Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
RESIDENTIAL													
Home Insulation	-	-	-	-	0.3	2.2	3.9	5.6	7.6	9.0	10.2	10.2	10.2
Affordable Energy Program	-	-	-	-	-	-	0.0	0.1	0.7	2.3	3.5	3.5	3.5
Water & Energy Saver	-	-	-	-	-	-	-	-	-	0.8	1.8	1.8	1.8
	-	-	-	-	0.3	2.2	3.9	5.6	8.3	12.2	15.4	15.4	15.4
DISCONTINUED/COMPLETED													
Res HE Gas Furnace - Boiler	-	-	-	-	0.6	2.6	4.0	5.8	6.9	7.0	7.0	7.0	7.0
New Home Program	-	-	-	0.0	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.6	0.6
Thermostat	-	-	-	-	-	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	-	-	-	0.0	0.7	2.9	4.4	6.3	7.5	7.7	7.7	7.7	7.7
RESIDENTIAL TOTAL	-	-	-	0.0	1.0	5.0	8.3	11.9	15.8	19.8	23.1	23.1	23.1
COMMERCIAL													
HVAC	-	-	-	-	-	0.4	2.5	4.8	6.2	6.2	7.2	7.2	7.2
Commercial Insulation*	-	-	-	-	-	0.3	1.1	2.1	3.2	5.4	6.8	6.8	6.8
Commercial Windows*	-	-	-	-	-	0.0	0.1	0.2	0.5	0.8	1.3	1.3	1.3
City of Winnipg Agreement	-	0.1	0.1	0.2	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8
CBOP	-	-	-	-	-	-	-	0.1	0.2	0.4	0.4	0.4	0.4
Commercial New Buildings	-	-	-	-	-	-	-	-	-	-	0.4	0.4	0.4
Commercial Custom Measures	-	-	-	-	-	-	-	-	0.1	0.2	0.3	0.3	0.3
Commercial Kitchen Appliances	-	-	-	-	-	-	-	0.0	0.0	0.1	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	0.1	0.1	0.2	0.6	1.4	4.4	8.0	11.0	13.8	17.2	17.2	17.2
DISCONTINUED/COMPLETED													
Power Smart Shops	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	0.8	1.1	2.1	2.4	2.4	-	-	-
	-	-	-	-	-	0.8	1.1	2.1	2.4	2.4	0.0	0.0	0.0
COMMERCIAL TOTAL	-	0.1	0.1	0.2	0.6	2.2	5.5	10.1	13.4	16.2	17.2	17.2	17.2
INDUSTRIAL													
Industrial Natural Gas Optimization	-	-	-	-	-	-	1.7	3.8	4.9	8.0	10.5	10.5	10.5
INDUSTRIAL TOTAL	-	-	-	-	-	-	1.7	3.8	4.9	8.0	10.5	10.5	10.5
EFFICIENCY PROGRAMS SUBTOTAL	-	0.1	0.1	0.2	1.6	7.3	15.5	25.9	34.1	44.0	50.9	50.9	50.9
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	-	(0.0)	(0.0)	(1.2)	(2.6)	(3.0)	(3.8)	(5.9)	(8.9)	(10.5)	(11.3)	(11.3)	(11.3)
NET IMPACT: OVERALL	-	0.1	0.1	(1.0)	(1.0)	4.3	11.7	20.0	25.3	33.5	39.6	39.6	39.6

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL													
Home Insulation	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Affordable Energy Program	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Water & Energy Saver	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4
DISCONTINUED/COMPLETED													
Res HE Gas Furnace - Boiler	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
New Home Program	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Thermostat	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
RESIDENTIAL TOTAL	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
COMMERCIAL													
HVAC	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Commercial Insulation*	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Commercial Windows*	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
City of Winnipg Agreement	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CBOP	0.4	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-	-	-
Commercial New Buildings	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Custom Measures	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Kitchen Appliances	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-
	17.2	17.2	17.2	17.2	17.2	17.2	16.8	16.8	16.8	16.8	16.8	16.8	16.8
DISCONTINUED/COMPLETED													
Power Smart Shops	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COMMERCIAL TOTAL	17.2	17.2	17.2	17.2	17.2	17.2	16.9	16.9	16.9	16.9	16.9	16.9	16.9
INDUSTRIAL													
Industrial Natural Gas Optimization	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
INDUSTRIAL TOTAL	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
EFFICIENCY PROGRAMS SUBTOTAL	50.9	50.9	50.9	50.9	50.9	50.9	50.5	50.5	50.5	50.5	50.5	50.5	50.5
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)
NET IMPACT: OVERALL	39.6	39.6	39.6	39.6	39.6	39.6	39.2	39.2	39.2	39.2	39.2	39.2	39.2

Note: Subtotals may not be exact due to rounding.
* Programs comprise Commercial Building Envelope Program.

Persisting Gas Savings - million m3
Natural Gas Incentive Based Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Affordable Energy Program	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Water & Energy Saver	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4
DISCONTINUED/COMPLETED													
Res HE Gas Furnace - Boiler	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
New Home Program	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Thermostat	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
RESIDENTIAL TOTAL	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
COMMERCIAL													
HVAC	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Commercial Insulation*	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Commercial Windows*	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
City of Winnipg Agreement	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial New Buildings	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Commercial Custom Measures	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial Kitchen Appliances	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-
	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
DISCONTINUED/COMPLETED													
Power Smart Shops	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COMMERCIAL TOTAL	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
INDUSTRIAL													
Industrial Natural Gas Optimization	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
INDUSTRIAL TOTAL	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
EFFICIENCY PROGRAMS SUBTOTAL	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5	50.5
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)	(11.3)
NET IMPACT: OVERALL	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2

Note: Subtotals may not be exact due to rounding.
* Programs comprise Commercial Building Envelope Program.

Total Annual Gas Savings - million m^3
Natural Gas Incentive Based Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
RESIDENTIAL												
Home Insulation	-	-	-	-	0.3	2.2	3.9	5.6	7.6	9.0	10.2	11.3
Affordable Energy Program	-	-	-	-	-	-	0.0	0.1	0.7	2.3	3.5	4.6
Water & Energy Saver	-	-	-	-	-	-	-	-	-	0.8	1.8	2.8
	-	-	-	-	0.3	2.2	3.9	5.6	8.3	12.2	15.4	18.7
DISCONTINUED/COMPLETED												
Res HE Gas Furnace - Boiler	-	-	-	-	0.6	2.6	4.0	5.8	6.9	7.0	7.0	7.0
New Home Program	-	-	-	0.0	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.6
Thermostat	-	-	-	-	-	0.1	0.2	0.2	0.2	0.2	0.2	0.2
	-	-	-	0.0	0.7	2.9	4.4	6.3	7.5	7.7	7.7	7.7
RESIDENTIAL TOTAL	-	-	-	0.0	1.0	5.0	8.3	11.9	15.8	19.8	23.1	26.4
COMMERCIAL												
HVAC	-	-	-	-	-	0.4	2.5	4.8	6.2	6.2	7.2	8.4
Commercial Insulation*	-	-	-	-	-	0.3	1.1	2.1	3.2	5.4	6.8	7.8
Commercial New Buildings	-	-	-	-	-	-	-	-	-	-	0.4	2.8
Commercial Windows*	-	-	-	-	-	0.0	0.1	0.2	0.5	0.8	1.3	1.6
Commercial Custom Measures	-	-	-	-	-	-	-	-	0.1	0.2	0.3	1.4
City of Winnipg Agreement	-	0.1	0.1	0.2	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8
CBOP	-	-	-	-	-	-	-	0.1	0.2	0.4	0.4	0.4
Commercial Kitchen Appliances	-	-	-	-	-	-	-	0.0	0.0	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-
	-	0.1	0.1	0.2	0.6	1.4	4.4	8.0	11.0	13.8	17.2	23.3
DISCONTINUED/COMPLETED												
Power Smart Shops	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	0.8	1.1	2.1	2.4	2.4	-	-
	-	-	-	-	-	0.8	1.1	2.1	2.4	2.4	0.0	0.0
COMMERCIAL TOTAL	-	0.1	0.1	0.2	0.6	2.2	5.5	10.1	13.4	16.2	17.2	23.4
INDUSTRIAL												
Industrial Natural Gas Optimization	-	-	-	-	-	-	1.7	3.8	4.9	8.0	10.5	12.5
INDUSTRIAL TOTAL	-	-	-	-	-	-	1.7	3.8	4.9	8.0	10.5	12.5
EFFICIENCY PROGRAMS SUBTOTAL	-	0.1	0.1	0.2	1.6	7.3	15.5	25.9	34.1	44.0	50.9	62.2
CUSTOMER SELF-GENERATION												
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	-	(0.0)	(0.0)	(1.2)	(2.6)	(3.0)	(3.8)	(5.9)	(8.9)	(10.5)	(11.3)	(12.0)
NET IMPACT: OVERALL	-	0.1	0.1	(1.0)	(1.0)	4.3	11.7	20.0	25.3	33.5	39.6	50.1

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Home Insulation	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Affordable Energy Program	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Water & Energy Saver	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
DISCONTINUED/COMPLETED														
Res HE Gas Furnace - Boiler	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
New Home Program	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Thermostat	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
RESIDENTIAL TOTAL	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4
COMMERCIAL														
HVAC	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Commercial Insulation*	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Commercial New Buildings	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Commercial Windows*	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Commercial Custom Measures	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
City of Winnipg Agreement	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CBOP	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.1	0.1	-	-	-	-	-
Commercial Kitchen Appliances	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.0	23.0	22.9	22.9	22.9	22.9	22.9
DISCONTINUED/COMPLETED														
Power Smart Shops	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COMMERCIAL TOTAL	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.0	23.0	22.9	22.9	22.9	22.9	22.9
INDUSTRIAL														
Industrial Natural Gas Optimization	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
INDUSTRIAL TOTAL	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
EFFICIENCY PROGRAMS SUBTOTAL	62.2	62.2	62.2	62.2	62.2	62.2	62.2	61.8	61.8	61.8	61.8	61.8	61.8	61.8
CUSTOMER SELF-GENERATION														
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(12.1)	(12.1)	(12.2)	(12.1)	(12.1)	(12.2)	(12.2)	(12.3)	(12.3)	(12.3)	(11.5)	(11.5)	(11.5)	(11.5)
NET IMPACT: OVERALL	50.1	50.1	50.0	50.1	50.1	50.0	50.0	49.6	49.6	49.5	50.3	50.2	50.2	50.3

Note: Subtotals may not be exact due to rounding.
* Programs comprise Commercial Building Envelope Program.

Total Annual Gas Savings - million m^3
Natural Gas Incentive Based Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Home Insulation	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Affordable Energy Program	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Water & Energy Saver	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
DISCONTINUED/COMPLETED													
Res HE Gas Furnace - Boiler	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
New Home Program	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Thermostat	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
RESIDENTIAL TOTAL	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4	26.4
COMMERCIAL													
HVAC	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Commercial Insulation*	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Commercial New Buildings	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Commercial Windows*	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Commercial Custom Measures	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
City of Winnipg Agreement	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CBOP	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Kitchen Appliances	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial Washers	-	-	-	-	-	-	-	-	-	-	-	-	-
	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
DISCONTINUED/COMPLETED													
Power Smart Shops	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Rinse and Save	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COMMERCIAL TOTAL	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
INDUSTRIAL													
Industrial Natural Gas Optimization	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
INDUSTRIAL TOTAL	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
EFFICIENCY PROGRAMS SUBTOTAL	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
LESS: INTERACTIVE EFFECTS	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.5)	(11.6)	(11.6)	(11.6)	(11.6)	(11.6)	(11.6)
NET IMPACT: OVERALL	50.3	50.3	50.2	50.2	50.2	50.2	50.2	50.1	50.1	50.1	50.1	50.1	50.1

Note: Subtotals may not be exact due to rounding.
* Programs comprise Commercial Building Envelope Program.

Appendix I

Energy Savings - DSM Support Programs

2012/13 Annual Energy Savings - GW.h
Electric DSM Support Programs

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL															
Power Smart Residential Loan	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Residential Earth Power Loan	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Residential PAYS	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
COMMERCIAL															
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED															
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
GW.h IMPACTS (at generation)	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30

Note: Subtotals may not be exact due to rounding.

2012/13 Annual Energy Savings - GW.h
Electric DSM Support Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL															
Power Smart Residential Loan	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.69	0.69
Residential Earth Power Loan	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.56	0.56
Residential PAYS	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.30	1.30
COMMERCIAL															
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED															
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	N/A	N/A
GW.h IMPACTS (at generation)	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30

Note: Subtotals may not be exact due to rounding.

Persisting Energy Savings - GW.h
Electric DSM Support Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	1.0	2.8	4.8	6.1	8.8	10.2	11.2	11.8	12.8	12.8	14.6	14.6
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	0.9	1.6	2.2	2.7	3.2	3.9	4.6	5.2	6.9	7.4	7.8	7.8	8.8	8.8
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.3	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	0.9	2.0	3.4	6.3	8.7	10.8	14.2	16.1	18.9	20.0	21.3	21.3	24.3	24.3
COMMERCIAL																										
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																										
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.2	2.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	3.2	3.2
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1
	-	-	-	-	-	-	-	-	-	-	-	-	0.7	1.4	2.6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.5	3.5
GW.h IMPACTS (at meter)	-	-	-	-	-	-	-	-	-	-	-	-	1.6	3.4	6.0	9.3	11.7	13.8	17.2	19.1	21.9	23.0	24.4	24.4	N/A	N/A
GW.h IMPACTS (at generation)	-	-	-	-	-	-	-	-	-	-	-	-	1.9	3.9	6.8	10.6	13.4	15.7	19.6	21.8	24.9	26.2	27.8	27.8	27.8	27.8

Note: Subtotals may not be exact due to rounding.

Persisting Energy Savings - GW.h
Electric DSM Support Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL																											
Residential Earth Power Loan	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Power Smart Residential Loan	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
ecoENERGY	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
COMMERCIAL																											
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																											
PSEM	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
R-2000 Component of the New Home Program	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar Hot Water Heating	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
GW.h IMPACTS (at meter)	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
GW.h IMPACTS (at generation)	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8

Note: Subtotals may not be exact due to rounding.

2012/13 Annual Energy Savings - GW.h
Electric DSM Support Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01
RESIDENTIAL												
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
COMMERCIAL												
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED												
PSEM	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at generation)	-	-	-	-	-	-	-	-	-	-	-	-

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL														
Residential Earth Power Loan	-	0.3	1.0	2.8	4.8	6.1	8.8	10.2	11.2	11.8	12.8	13.4	15.3	15.3
Power Smart Residential Loan	0.9	1.6	2.2	2.7	3.2	3.9	4.6	5.2	6.9	7.4	7.8	8.2	9.4	9.4
ecoENERGY	-	0.1	0.3	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.9	2.0	3.4	6.3	8.7	10.8	14.2	16.1	18.9	20.0	21.3	22.5	25.6	25.6
COMMERCIAL														
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED														
PSEM	0.6	1.2	2.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	3.2	3.2
R-2000 Component of the New Home Program	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1
	0.7	1.4	2.6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.5	3.5
GW.h IMPACTS (at meter)	1.6	3.4	6.0	9.3	11.7	13.8	17.2	19.1	21.9	23.0	24.4	25.5	N/A	N/A
GW.h IMPACTS (at generation)	1.9	3.9	6.8	10.6	13.4	15.7	19.6	21.8	24.9	26.2	27.8	29.1	29.1	29.1

Note: Subtotals may not be exact due to rounding.

2012/13 Annual Energy Savings - GW.h
Electric DSM Support Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Residential Earth Power Loan	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Power Smart Residential Loan	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
ecoENERGY	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
COMMERCIAL														
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED														
PSEM	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
R-2000 Component of the New Home Program	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar Hot Water Heating	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
GW.h IMPACTS (at meter)	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
GW.h IMPACTS (at generation)	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Residential Earth Power Loan	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Power Smart Residential Loan	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
ecoENERGY	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
R-2000 Component of the New Home Program	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Solar Hot Water Heating	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
GW.h IMPACTS (at meter)	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
GW.h IMPACTS (at generation)	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1

Note: Subtotals may not be exact due to rounding.

Appendix J

Average Winter Savings - DSM Support Programs

2012/13 Average Winter MW
Electric DSM Support Programs

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL															
Power Smart Residential Loan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Residential Earth Power Loan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential PAYS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
COMMERCIAL															
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED															
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
GW.h IMPACTS (at generation)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Note: Subtotals may not be exact due to rounding.

2012/13 Average Winter MW
Electric DSM Support Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL															
Power Smart Residential Loan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Residential Earth Power Loan	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential PAYS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
COMMERCIAL															
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED															
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GW.h IMPACTS (at meter)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	N/A	N/A
GW.h IMPACTS (at generation)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Note: Subtotals may not be exact due to rounding.

Persisting Average Winter MW
Electric DSM Support Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.8	1.1	1.4	1.6	2.0	2.7	3.0	3.9	4.2	4.4	4.4	5.0	5.0
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.6	1.1	1.4	2.1	2.5	3.0	3.3	3.8	3.8	4.3	4.3
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.9	1.3	2.0	2.7	3.4	4.8	5.5	6.9	7.5	8.2	8.2	9.3	9.3
COMMERCIAL																										
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																										
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MW IMPACTS (at meter)	-	-	-	-	-	-	-	-	-	-	-	-	0.5	1.0	1.5	2.2	2.9	3.6	5.0	5.7	7.1	7.7	8.4	8.4	N/A	N/A
MW IMPACTS (at generation)	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.2	1.7	2.5	3.3	4.1	5.7	6.5	8.1	8.8	9.5	9.5	9.5	9.5

Note: Subtotals may not be exact due to rounding.

Persisting Average Winter MW
Electric DSM Support Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL																											
Power Smart Residential Loan	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Residential Earth Power Loan	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
COMMERCIAL																											
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																											
PSEM	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MW IMPACTS (at meter)	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
MW IMPACTS (at generation)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5

Note: Subtotals may not be exact due to rounding.

Total Average Winter MW
Electric DSM Support Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	At Generation 2012/13	At Generation 2026/27
RESIDENTIAL																										
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.8	1.1	1.4	1.6	2.0	2.7	3.0	3.9	4.2	4.4	4.7	5.4	5.4
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.2	0.6	1.1	1.4	2.1	2.5	3.0	3.3	3.8	3.9	4.4	4.4
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	0.5	0.9	1.3	2.0	2.7	3.4	4.8	5.5	6.9	7.5	8.2	8.6	9.8	9.8
COMMERCIAL																										
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																										
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MW IMPACTS (at meter)	-	-	-	-	-	-	-	-	-	-	-	-	0.5	1.0	1.5	2.2	2.9	3.6	5.0	5.7	7.1	7.7	8.4	8.8	N/A	N/A
MW IMPACTS (at generation)	-	-	-	-	-	-	-	-	-	-	-	-	0.6	1.2	1.7	2.5	3.3	4.1	5.7	6.5	8.1	8.8	9.5	10.0	10.0	10.0

Note: Subtotals may not be exact due to rounding.

Total Average Winter MW
Electric DSM Support Programs

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL																											
Power Smart Residential Loan	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Residential Earth Power Loan	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Residential PAYS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
COMMERCIAL																											
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																											
PSEM	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MW IMPACTS (at meter)	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
MW IMPACTS (at generation)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

Note: Subtotals may not be exact due to rounding.

Appendix K

Natural Gas Savings (m^3) - DSM Support Programs

2012/13 Natural Gas Savings - million m3
Natural Gas DSM Support Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL																										
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
	-	-	-	-	-	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
COMMERCIAL																										
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED																										
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

Note: Subtotals may not be exact due to rounding.

2012/13 Natural Gas Savings - million m3
Natural Gas DSM Support Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Residential Earth Power Loan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Power Smart Residential Loan	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
ecoENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-
Residential PAYS	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	-	-	-	-	-	-	-	-	-	-	-	-	-
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6

Note: Subtotals may not be exact due to rounding.

Persisting Natural Gas Savings - million m3
Natural Gas DSM Suport Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
RESIDENTIAL													
Power Smart Residential Loan	1.2	2.1	3.5	5.6	7.8	9.6	11.3	12.3	13.9	14.3	14.6	14.6	14.6
Residential Earth Power Loan	-	0.1	0.1	0.5	0.8	1.0	1.3	1.4	1.7	2.1	2.4	2.4	2.4
ecoENERGY	-	0.1	0.4	1.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	1.2	2.3	4.0	7.3	10.9	12.8	14.9	16.1	17.9	18.7	19.3	19.3	19.3
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	(0.0)	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0
	(0.0)	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	1.2	2.4	4.3	7.7	11.3	13.2	15.3	16.4	18.3	19.0	19.7	19.7	19.7

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL													
Power Smart Residential Loan	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Residential Earth Power Loan	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
ecoENERGY	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7

Note: Subtotals may not be exact due to rounding.

Persisting Natural Gas Savings - million m3
Natural Gas DSM Suport Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Power Smart Residential Loan	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Residential Earth Power Loan	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
ecoENERGY	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3	19.3
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7

Note: Subtotals may not be exact due to rounding.

Total Annual Natural Gas Savings - million m3
Natural Gas DSM Support Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
RESIDENTIAL												
Power Smart Residential Loan	1.2	2.1	3.5	5.6	7.8	9.6	11.3	12.3	13.9	14.3	14.6	14.9
Residential Earth Power Loan	-	0.1	0.1	0.5	0.8	1.0	1.3	1.4	1.7	2.1	2.4	2.7
ecoENERGY	-	0.1	0.4	1.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	-	-	-	-	-	-	-	-	-	-	-	(0.0)
	1.2	2.3	4.0	7.3	10.9	12.8	14.9	16.1	17.9	18.7	19.3	19.9
COMMERCIAL												
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED												
PSEM	(0.0)	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
	(0.0)	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	1.2	2.4	4.3	7.7	11.3	13.2	15.3	16.4	18.3	19.0	19.7	20.3

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
RESIDENTIAL														
Power Smart Residential Loan	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
Residential Earth Power Loan	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
ecoENERGY	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
COMMERCIAL														
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED														
PSEM	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3

Note: Subtotals may not be exact due to rounding.

Total Annual Natural Gas Savings - million m3
Natural Gas DSM Support Programs

	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40
RESIDENTIAL													
Power Smart Residential Loan	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
Residential Earth Power Loan	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
ecoENERGY	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Residential PAYS	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
COMMERCIAL													
Commercial PAYS	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISCONTINUED/COMPLETED													
PSEM	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
R-2000 Component of the New Home Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Hot Water Heating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
TOTAL	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3

Note: Subtotals may not be exact due to rounding.

Appendix L

Annual Energy Savings - Codes & Standards (GW.h, MW & m^3)

Annual Energy Savings - GW.h
Codes & Standards

	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Residential Appliances:																					
Ranges	0.4	-0.2	-0.1	0.1	-0.3	-0.1	-0.1	-0.1	-0.3	0.2	0.2	0.0	0.0	0.1	-0.2	-0.2	-0.2	3.4	3.2	1.4	1.2
Dishwashers	0.0	0.1	0.2	0.4	0.7	0.8	0.7	0.7	0.7	0.8	0.8	1.3	2.0	2.0	2.5	3.4	3.5	0.2	0.2	0.1	0.1
Clothes Washers	-0.3	-0.3	0.1	0.1	0.1	0.2	0.6	0.8	0.8	0.8	0.7	0.9	3.0	3.1	3.9	3.6	3.8	0.2	0.2	0.1	0.0
Clothes Dryers	0.1	0.1	0.4	0.4	4.6	0.5	0.1	0.1	0.1	0.2	0.2	0.2	1.0	1.0	1.0	0.9	0.9	13.9	15.8	9.0	8.0
Refrigerators	2.0	4.7	6.1	7.1	7.0	7.2	7.1	7.2	7.8	7.8	10.1	11.0	12.9	13.2	12.8	16.2	17.1	18.7	10.9	10.2	9.1
Freezers	-0.3	0.3	0.4	0.5	0.7	0.4	0.5	0.5	0.5	0.5	0.3	0.3	0.5	-0.8	-0.5	-0.7	-0.8	3.1	2.6	6.5	6.2
Residential Insulation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.0	1.0	1.1	1.2	1.5	0.8	1.2	1.3	1.5	2.8	2.9	1.7	3.5
Other Residential Equipment[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	21.3	22.3
Commercial Lighting	0.0	0.0	0.0	0.0	0.0	9.7	15.4	16.5	14.9	16.3	19.2	0.5	0.4	0.3	0.3	0.3	0.3	0.4	0.4	12.8	15.2
Other Commercial Equipment[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial Equipment - High Efficiency Motors	0.0	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	1.9	4.6	7.1	8.6	12.8	20.3	26.0	28.6	27.2	29.2	34.2	16.9	22.9	21.4	22.5	24.8	26.1	42.5	45.1	63.1	65.6
GW.h IMPACTS (at meter)	1.9	4.6	7.1	8.6	12.8	20.3	26.0	28.6	27.2	29.2	34.2	16.9	22.9	21.4	22.5	24.8	26.1	42.5	45.1	63.1	65.6
GW.h IMPACTS (at generation)	2.2	5.3	8.1	9.8	14.6	23.1	29.6	32.5	30.9	33.3	39.0	19.2	26.1	24.3	25.6	28.3	29.8	48.5	51.4	71.9	74.8

Note: Subtotals may not be exact due to rounding.
[1]Category includes: central air conditioning, electric hot water tank, furnace, attic insulation, windows, heat recovery ventilator (HRV), efficient showerheads and electronic fireplace ignition.
[2]Category includes: commercial spray valves.

Annual Energy Savings - MW
Codes & Standards

	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Residential Appliances:																					
Ranges	0.1	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	1.3	1.2	0.3	0.2
Dishwashers	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.5	0.5	0.6	0.8	0.9	0.0	0.0	0.0	0.0
Clothes Washers	-0.1	-0.1	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.7	0.8	1.0	0.9	0.9	0.0	0.0	0.0	0.0
Clothes Dryers	0.0	0.0	0.1	0.1	1.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	1.8	2.1	1.8	1.6
Refrigerators	0.5	1.1	1.5	1.7	1.7	1.8	1.7	1.8	1.9	1.9	2.5	2.7	3.1	3.2	3.1	4.0	4.2	2.1	1.2	1.3	1.1
Freezers	-0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.2	-0.1	-0.2	-0.2	0.3	0.3	0.8	0.7
Residential Insulation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.5	0.3	0.4	0.5	0.5	1.2	2.2	0.9	1.9
Other Residential Equipment[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	6.6	7.3
Commercial Lighting	0.0	0.0	0.0	0.0	0.0	2.7	4.3	4.7	4.2	4.6	5.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	3.5	4.2
Other Commercial Equipment[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial Equipment - High Efficiency Motors	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	0.5	1.1	1.7	2.1	3.0	5.2	6.8	7.6	7.2	7.8	9.1	4.1	5.6	5.2	5.5	6.2	6.5	6.9	7.5	15.1	17.0
MW IMPACTS (at meter)	0.5	1.1	1.7	2.1	3.0	5.2	6.8	7.6	7.2	7.8	9.1	4.1	5.6	5.2	5.5	6.2	6.5	6.9	7.5	15.1	17.0
MW IMPACTS (at generation)	0.5	1.3	2.0	2.4	3.4	5.9	7.7	8.7	8.2	8.8	10.3	4.7	6.4	5.9	6.2	7.0	7.4	7.8	8.5	17.2	19.4

Note: Subtotals may not be exact due to rounding.
[1]Category includes: central air conditioning, electric hot water tank, furnace, attic insulation, windows, heat recovery ventilator (HRV), efficient showerheads and electronic fireplace ignition.
[2]Category includes: commercial spray valves.

Annual Energy Savings - millions m^3
Codes & Standards

	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Residential Appliances:																					
Dishwashers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Clothes Washers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.0	0.2	0.1	0.1
Furnaces:																					
Residential - Federal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.1
Residential - Provincial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Commercial - Federal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Residential - Provincial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Insulation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.5	0.3
Other Residential Equipment[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.4	2.5
Other Commercial Equipment[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millions m^3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.5	0.9	5.5	3.4

Note: Subtotals may not be exact due to rounding.
[1]Category includes: furnace, attic insulation, windows, heat recovery ventilator (HRV) and electronic fireplace ignition.
[2]Category includes: commercial spray valves.

Appendix M

Electric Incentive-Based Utility, Administration & Incentive Costs

Total Power Smart Utility Costs - Including Affordable Energy Costs (1000s in 2012$)
Electric Incentive-Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL																									
Refrigerator Retirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	83	1,503	1,600	3,197
Home Insulation	0	0	0	0	259	395	247	230	415	46	5	46	73	72	141	779	1,160	1,978	1,595	1,763	1,752	1,413	1,275	1,265	14,910
Affordable Energy Program*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	106	220	1,198	2,000	699	813	927	6,009
Water & Energy Saver	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	83	52	473	446	775	1,848
Affordable Energy First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	14	2	6	40	59	145	185	457
	0	0	0	0	259	395	247	230	415	46	5	46	73	72	142	779	1,229	2,098	1,817	3,050	3,855	2,727	4,182	4,752	26,421
DISCONTINUED/COMPLETED																									
New Home	0	0	0	40	155	98	222	126	64	34	1	19	136	300	229	313	628	938	673	668	601	217	253	45	5,761
Residential Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	21	14	11	99	1,601	2,036	1,810	415	12	1	1	6,022
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	820	1,061	848	972	1,338	1,651	1,039	2	0	7,751
Programmable Thermostats	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	73	36	10	0	0	0	0	141
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88	405	377	357	24	0	0	0	1,252
Residential Hot Water	0	0	179	0	0	0	2	63	26	16	4	0	0	0	0	0	0	0	0	0	0	0	0	0	289
Outdoor Timer	202	295	252	197	96	56	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1,134
Retrofit/Demonstration	0	66	27	124	0	0	4	0	0	0	0	0	0	0	0	14	48	0	0	0	0	0	0	0	284
Refrigerator/Freezer Buy-Back	0	0	54	12	0	0	0	0	0	0	0	0	0	17	29	5	68	25	0	0	0	0	0	0	211
Water Heater Rental	0	0	0	0	0	0	19	407	403	77	5	0	0	0	0	0	0	0	0	0	0	0	0	0	911
High Efficiency Furnace/Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	3
Energy Efficiency Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	161	517	400	193	252	315	0	1,839
Aboriginal Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	0	0	0	0	0	0	20
	202	361	512	373	251	154	267	599	503	130	11	19	136	338	303	1,167	2,008	4,068	4,612	4,585	2,884	1,520	572	46	25,619
RESIDENTIAL EXPLORATORY PROGRAMS																									
New Home Program (Re-design)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	27
LED Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Residential Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	4
Set Top Boxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	1	0	0	22
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	3	2	28	53
RESIDENTIAL TOTAL	202	361	512	373	510	549	513	829	918	176	15	65	209	410	445	1,946	3,237	6,166	6,429	7,635	6,760	4,250	4,756	4,826	52,093
COMMERCIAL																									
Commercial Lighting	0	0	111	1,183	2,537	2,993	2,937	1,220	1,038	2,054	917	671	1,041	1,233	2,784	5,486	6,616	7,586	7,839	8,132	7,584	6,884	6,437	7,757	85,043
Commercial Windows**	0	0	0	0	8	27	43	131	173	63	45	77	69	159	123	249	330	410	400	464	1,054	1,261	1,001	925	7,013
Internal Retrofit	0	0	120	284	475	572	166	215	178	234	116	298	141	289	636	726	618	5,025	4,603	2,763	2,232	1,931	756	811	23,188
Commercial Refrigeration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	244	323	309	183	191	176	340	613	2,379
Commercial Insulation**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	224	268	250	239	276	236	451	1,943
Commercial Earth Power	0	0	0	0	15	50	80	67	229	119	137	112	172	293	659	283	530	656	370	233	400	308	295	265	5,272
Commercial HVAC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	183	212	75	223	168	324	213	149	1,546
Commercial New Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	146	100	169	300	302	116	1,136
Commercial Building Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	61	42	29	27	37	40	92	517
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58	45	143	66	64	59	434
Commercial Custom	0	0	0	0	20	68	109	81	0	223	540	135	151	83	161	12	8	124	197	251	219	239	241	56	2,917
Commercial Kitchen Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	86	37	32	12	262
Commercial Network Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	21	71	86	24	6	210
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	4	2,941	2,016	4,820	1,907	210	66	47	82	-45	-120	11,927
	0	0	231	1,467	3,054	3,709	3,335	1,714	1,617	2,694	1,754	1,294	1,574	2,062	7,304	8,771	13,538	16,529	14,520	12,856	12,631	12,008	9,934	11,190	143,786
DISCONTINUED/COMPLETED																									
Commercial Parking Lot Controllers	0	0	0	0	40	135	218	115	104	195	21	53	209	114	296	373	1,108	957	614	397	532	548	286	9	6,323
Commercial Air Conditioners	0	0	0	0	1	2	3	82	77	0	0	0	7	55	0	141	11	0	0	0	0	0	0	1	380
Agricultural Heat Pads	0	0	0	0	0	0	3	69	36	92	92	49	62	70	62	133	76	69	63	45	120	102	8	1	1,152
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	63	252	147	47	0	511
Power Smart Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	83	122	90	113	22	0	431
Commercial Rinse & Save	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	29	23	9	5	0	0	107
Commercial Air Barriers	0	0	0	0	8	28	46	100	79	3	11	34	22	18	19	7	4	0	6	0	0	0	0	0	386
Livestock Waterer	0	0	0	0	0	157	136	95	24	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	416
Roadway Lighting	0	115	1,523	2,149	1,963	1,491	18	0	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,307
Sentinel Lighting	0	32	1,343	1,125	1,154	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,655
Agricultural Demand Controller	0	0	33	642	218	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	893
Commercial Showerheads	0	66	122	36	4	123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	351
Infrared Heat Lamps	0	18	293	33	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	350
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	0	232	3,315	3,985	3,393	1,936	423	462	368	294	124	136	300	256	377	654	1,199	1,066	797	650	1,004	915	363	11	22,262
COMMERCIAL EXPLORATORY PROGRAMS																									
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
COMMERCIAL TOTAL	0	232	3,546	5,452	6,447	5,645	3,758	2,175	1,985	2,988	1,878	1,430	1,874	2,319	7,681	9,425	14,737	17,595	15,317	13,507	13,635	12,924	10,298	11,201	166,049
INDUSTRIAL																									
Performance Optimization	0	0	89	191	245	504	510	459	669	406	269	416	1,052	3,323	1,249	1,693	1,765	1,132	3,385	2,637	3,043	2,866	2,979	2,741	31,623
Emergency Preparedness	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	85	73	7	1	0	167
	0	0	89	191	245	504	510	459	669	406	269	416	1,052	3,323	1,249	1,693	1,765	1,132	3,385	2,722	3,116	2,873	2,980	2,741	31,789
DISCONTINUED/COMPLETED																									
High Efficiency Motors	0	23	317	770	616	490	449	486	655	47	3	0	0	0	0	0	0	0	0	0	0	0	0	0	3,856
Industrial Retrofit/Demonstration	0	0	64	326	349	627	1,077	365	335	86	11	5	0	0	0	0	0	39	0	0	0	0	0	0	3,283
Efficient Motors (QMR)	0	0	0	23	53	20	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
	0	23	381	1,118	1,018	1,137	1,530	851	990	134	14	5	0	0	0	0	0	39	0	0	0	0	0	0	7,240
INDUSTRIAL TOTAL	0	23	471	1,310	1,263	1,640	2,040	1,310	1,659	540	284	421	1,052	3,323	1,249	1,693	1,765	1,171	3,385	2,722	3,116	2,873	2,980	2,741	39,029
EFFICIENCY PROGRAMS SUBTOTAL	202	616	4,528	7,135	8,220	7,835	6,311	4,315	4,563	3,704	2,177	1,916	3,135	6,051	9,375	13,064	19,738	24,933	25,130	23,864	23,511	20,047	18,033	18,768	257,171
												1,897													
CUSTOMER SELF-GENERATION PROGRAMS																									
Bioenergy Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	1,783	1,723	1,810	1,556	1,661	1,749	348	10,784
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	1,783	1,723	1,810	1,556	1,661	1,749	348	10,784
RATE/LOAD MANAGEMENT PROGRAMS																									
Curtailable Rates	0	0	0	88	649	1,592	1,433	1,404	1,215	1,553	1,920	2,462	3,244	4,892	6,406	6,423	7,160	7,005	6,945	6,720	6,031	5,944	5,880	5,751	84,717
	0	0	0	88	649	1,592	1,433	1,404	1,215	1,553	1,920	2,462	3,244	4,892	6,406	6,423	7,160	7,005	6,945	6,720	6,031	5,944	5,880	5,751	84,717
Support Costs***	0	366	3,520	4,230	3,006	1,672	1,986	1,596	1,270	1,648	2,345	3,215	2,891	3,658	3,737	4,170	4,432	7,198	7,178	6,341	5,509	4,109	7,165	5,225	86,466
UTILITY COST OF PROGRAMS	202	982	8,048	11,453	11,874	11,100	9,730	7,315	7,048	6,904	6,442	7,593	9,270	14,601	19,518	23,657	31,485	40,919	40,976	38,734	36,606	31,761	32,827	30,091	439,137

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund expenditures.
** Programs comprise the Commercial Building Envelope Program.
*** Support Costs include Affordable Energy Fund spending.

Administration Cost (1000s in 2012$)
Electric Incentive-Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL																									
Refrigerator Retirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	83	1,179	1,239	2,513
Affordable Energy Program*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	0	178	884	1,215	82	749	839	3,991
Home Insulation	0	0	0	0	259	395	247	230	415	46	5	46	73	72	141	282	444	298	222	222	196	221	245	440	4,500
Water & Energy Saver	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	83	52	87	259	359	858
Affordable Energy First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	14	2	6	40	59	145	185	457
	0	0	0	0	259	395	247	230	415	46	5	46	73	72	142	282	513	312	402	1,195	1,514	532	2,576	3,063	12,320
DISCONTINUED/COMPLETED																									
New Home	0	0	0	40	155	98	222	126	64	34	1	19	136	300	229	302	558	806	556	562	483	93	207	33	5,024
Residential Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	21	14	11	99	584	635	426	112	12	1	0	1,915
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	657	787	608	709	657	534	421	2	0	4,395
Programmable Thermostats	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	50	25	5	0	0	0	0	102
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56	241	260	287	2	0	0	0	845
Residential Hot Water	0	0	170	0	0	0	2	63	26	16	4	0	0	0	0	0	0	0	0	0	0	0	0	0	280
Outdoor Timer	152	226	191	161	66	56	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	889
Retrofit/Demonstration	0	66	27	124	0	0	0	0	0	0	0	0	0	0	0	14	48	0	0	0	0	0	0	0	280
Refrigerator/Freezer Buy-Back	0	0	27	12	0	0	0	0	0	0	0	0	0	17	29	5	68	0	0	0	0	0	0	0	160
Water Heater Rental	0	0	0	0	0	0	19	407	403	77	5	0	0	0	0	0	0	0	0	0	0	0	0	0	911
Energy Efficiency Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	64	409	327	128	98	185	0	1,211
High Efficiency Furnace/Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	3
	152	292	416	337	222	154	262	599	503	130	11	19	136	338	303	993	1,628	2,353	2,593	2,264	1,259	623	395	33	16,015
RESIDENTIAL EXPLORATORY PROGRAMS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	0	0	0	21
RESIDENTIAL TOTAL	152	292	416	337	481	549	509	829	918	176	15	65 65	209	410	445	1,275	2,141	2,666	2,995	3,459	2,794	1,155	2,972	3,096	28,356
COMMERCIAL																									
Commercial Lighting	0	0	111	872	971	805	650	445	577	431	318	340	416	843	1,150	1,948	1,897	2,245	2,138	1,925	1,978	1,928	1,872	1,764	25,625
Internal Retrofit	0	0	120	284	475	572	166	215	178	234	116	298	141	289	636	726	618	5,025	4,603	2,763	2,232	1,931	756	811	23,188
Commercial Windows**	0	0	0	0	8	27	43	81	77	8	1	25	13	43	32	62	55	161	168	105	120	122	118	168	1,438
Commercial Insulation**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	147	148	45	46	33	31	147	598
Commercial Refrigeration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	244	226	202	98	100	87	136	120	1,213
Commercial Earth Power	0	0	0	0	15	50	80	37	77	28	13	40	82	147	294	151	209	209	222	137	126	101	123	82	2,223
Commercial Building Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	61	42	21	18	28	27	68	453
Commercial New Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	169	186	190	37	683
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36	40	42	35	29	183
Commercial Custom	0	0	0	0	20	68	109	50	0	92	90	81	98	61	65	9	1	81	35	216	90	92	140	10	1,411
Commercial HVAC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	73	22	14	13	18	17	18	10	185
Commercial Kitchen Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	36	13	18	8	125
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	4	2,132	1,049	1,007	451	57	66	47	-81	-118	7	4,621
Commercial Network Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	67	73	24	6	190
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	2
	0	0	231	1,156	1,488	1,521	1,048	827	910	794	538	784	750	1,389	4,310	3,946	4,293	8,628	7,629	5,596	5,087	4,574	3,369	3,268	62,138
DISCONTINUED/COMPLETED																									
Commercial Parking Lot Controllers	0	0	0	0	40	135	218	81	77	70	5	33	159	90	222	293	512	186	122	149	151	82	32	1	2,657
Agricultural Heat Pads	0	0	0	0	0	0	3	69	36	42	30	21	24	33	28	83	45	44	29	19	33	28	8	1	575
Commercial Rinse & Save	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	16	5	6	1	0	0	42
Power Smart Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	119	90	113	22	0	345
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	63	250	144	47	0	505
Commercial Air Conditioners	0	0	0	0	1	2	3	81	77	0	0	0	3	20	0	12	2	0	0	0	0	0	0	0	200
Commercial Air Barriers	0	0	0	0	8	28	46	81	77	1	1	17	11	10	9	4	1	0	1	0	0	0	0	0	297
Livestock Waterer	0	0	0	0	0	136	118	83	24	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	366
Roadway Lighting	0	115	1,523	2,149	1,963	1,491	18	0	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,306
Sentinel Lighting	0	32	1,343	1,125	1,154	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,655
Agricultural Demand Controller	0	0	33	462	157	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	652
Commercial Showerheads	0	66	92	36	4	123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	321
Infrared Heat Lamps	0	18	158	33	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	215
	0	232	3,150	3,805	3,332	1,916	405	395	339	116	36	71	197	153	259	392	561	244	168	356	531	367	109	1	17,136
COMMERCIAL TOTAL	0	232	3,381	4,961	4,820	3,437	1,453	1,222	1,249	911	575	856	947	1,541	4,570	4,338	4,854	8,872	7,797	5,952	5,618	4,941	3,478	3,269	79,273
INDUSTRIAL																									
Performance Optimization	0	0	89	191	245	354	260	305	275	211	226	212	298	2,005	414	198	350	412	520	609	462	412	415	356	8,820
Emergency Preparedness	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	85	73	7	1	0	167
	0	0	89	191	245	354	260	305	275	211	226	212	298	2,005	414	198	350	412	520	694	534	419	416	356	8,987
DISCONTINUED/COMPLETED																									
High Efficiency Motors	0	23	279	352	273	239	256	278	351	47	3	0	0	0	0	0	0	0	0	0	0	0	0	0	2,103
Industrial Retrofit/Demonstration	0	0	64	288	293	216	403	365	335	47	11	5	0	0	0	0	0	39	0	0	0	0	0	0	2,067
Efficient Motors (QMR)	0	0	0	23	53	20	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
	0	23	343	664	620	475	663	642	686	95	14	5	0	0	0	0	0	39	0	0	0	0	0	0	4,270
INDUSTRIAL TOTAL	0	23	433	855	864	830	924	947	961	306	241	217	298	2,005	414	198	350	451	520	695	534	419	416	356	13,256
EFFICIENCY PROGRAMS SUBTOTAL	152	547	4,229	6,153	6,165	4,816	2,886	2,998	3,128	1,393	831	1,138 1,127	1,454	3,957	5,429	5,810	7,345	11,989	11,313	10,105	8,946	6,516	6,865	6,721	120,886
CUSTOMER SELF-GENERATION PROGRAMS																									
Bioenergy Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77	300	317	1,749	348	2,791
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77	300	317	1,749	348	2,791
RATE/LOAD MANAGEMENT PROGRAMS																									
Curtailable Rates	0	0	0	88	125	221	76	52	49	35	35	34	10	10	14	17	10	8	10	5	7	7	9	5	828
	0	0	0	88	125	221	76	52	49	35	35	34	10	10	14	17	10	8	10	5	7	7	9	5	828
Support Costs***	0	366	3,520	4,230	3,006	1,672	1,986	1,596	1,270	1,648	2,345	3,215	2,891	3,658	3,737	4,170	4,432	7,198	7,178	6,341	5,509	4,109	7,165	5,225	86,466
ADMINISTRATION COSTS OF PROGRAMS	152	913	7,749	10,472	9,296	6,709	4,948	4,646	4,447	3,075	3,211	4,387	4,355	7,624	9,180	9,997	11,786	19,195	18,501	16,529	14,761	10,949	15,788	12,299	210,970

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund expenditures.
** Programs comprise the Commercial Building Envelope Program.
*** Support Costs include Affordable Energy Fund spending.

Incentive Cost (1000s in 2012$)
Electric Incentive-Based Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL																									
Home Insulation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	497	715	1,680	1,373	1,541	1,556	1,192	1,030	825	10,410
Water & Energy Saver	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	386	187	417	990
Refrigerator Retirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	324	360	684
Affordable Energy Program*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	106	42	314	785	617	65	88	2,017
Affordable Energy First Nations Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	497	715	1,786	1,415	1,855	2,341	2,195	1,606	1,689	14,100
DISCONTINUED/COMPLETED																									
New Home	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	69	133	117	106	118	125	47	12	737
Residential Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,017	1,401	1,384	303	0	0	1	4,107
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	163	273	240	263	681	1,117	618	0	0	3,356
Programmable Thermostats	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	11	6	0	0	0	0	39
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	164	118	70	22	0	0	0	406
Residential Hot Water	0	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
Outdoor Timer	50	69	61	36	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	246
Retrofit/Demonstration	0	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Refrigerator/Freezer Buy-Back	0	0	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	0	0	0	0	0	0	52
Water Heater Rental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	98	108	73	65	154	130	0	628
High Efficiency Furnace/Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	50	69	96	36	30	0	4	0	0	0	0	0	0	0	0	174	375	1,700	2,018	2,321	1,625	897	176	13	9,584
RESIDENTIAL TOTAL	50	69	96	36	30	0	4	0	0	0	0	0	0	0	0	671	1,090	3,486	3,434	4,176	3,966	3,092	1,782	1,702	23,685
COMMERCIAL																									
Commercial Lighting	0	0	0	311	1,565	2,188	2,287	775	461	1,623	599	331	625	391	1,634	3,538	4,719	5,341	5,702	6,207	5,606	4,956	4,566	5,993	59,418
Commercial Windows**	0	0	0	0	0	0	0	50	96	55	43	53	56	116	91	186	276	250	232	359	934	1,139	883	757	5,575
Commercial Refrigeration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	96	106	85	91	89	204	493	1,165
Commercial Insulation**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	76	120	205	193	243	205	304	1,345
Commercial Earth Power	0	0	0	0	0	0	0	30	151	91	124	72	91	145	364	132	321	447	148	96	275	207	172	183	3,049
Commercial HVAC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110	190	61	209	150	307	195	140	1,361
Commercial New Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	146	0	0	114	113	79	453
Commercial Custom	0	0	0	0	0	0	0	30	0	130	450	53	52	22	96	3	7	43	162	35	129	146	101	46	1,506
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58	9	103	24	28	30	252
Commercial Building Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	9	9	13	24	63
Commercial Kitchen Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	47	50	24	14	3	137
Internal Retrofit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Network Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	5	12	0	0	19
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	809	966	3,812	1,456	154	0	0	163	72	-127	7,306
	0	0	0	311	1,565	2,188	2,287	886	708	1,899	1,215	509	824	674	2,994	4,825	9,245	7,901	6,890	7,261	7,544	7,434	6,566	7,923	81,649
DISCONTINUED/COMPLETED																									
Commercial Parking Lot Controllers	0	0	0	0	0	0	0	35	27	125	16	21	50	24	73	80	596	771	492	248	381	466	254	9	3,666
Commercial Air Conditioners	0	0	0	0	0	0	0	1	0	0	0	0	4	35	0	129	9	0	0	0	0	0	0	1	179
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	0	0	6
Power Smart Energy Manager	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	83	3	0	0	0	0	86
Commercial Rinse & Save	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26	14	18	3	5	0	0	65
Agricultural Heat Pads	0	0	0	0	0	0	0	0	0	51	62	28	38	37	35	50	31	25	34	25	87	74	0	0	577
Commercial Air Barriers	0	0	0	0	0	0	0	19	2	3	10	17	11	8	10	3	3	0	5	0	0	0	0	0	90
Livestock Waterer	0	0	0	0	0	21	18	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50
Roadway Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Agricultural Demand Controller	0	0	0	179	61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	241
Commercial Showerheads	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
Infrared Heat Lamps	0	0	135	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	135
	0	0	165	180	61	21	18	67	29	178	88	65	103	103	117	262	638	822	629	294	473	548	254	10	5,125
COMMERCIAL TOTAL	0	0	165	491	1,627	2,209	2,305	953	736	2,077	1,303	575	927	777	3,112	5,088	9,883	8,723	7,519	7,555	8,017	7,982	6,819	7,933	86,775
INDUSTRIAL																									
Performance Optimization	0	0	0	0	0	150	250	154	394	195	43	204	754	1,317	834	1,495	1,415	720	2,864	2,027	2,581	2,454	2,564	2,385	22,803
Emergency Preparedness	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	150	250	154	394	195	43	204	754	1,317	834	1,495	1,415	720	2,864	2,027	2,581	2,454	2,564	2,385	22,803
DISCONTINUED/COMPLETED																									
High Efficiency Motors	0	0	38	417	343	250	193	209	304	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,754
Industrial Retrofit/Demonstration	0	0	0	38	55	411	674	0	0	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,216
Efficient Motors (QMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	38	455	398	661	866	209	304	39	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,970
INDUSTRIAL TOTAL	0	0	38	455	398	811	1,116	363	698	234	43	204	754	1,317	834	1,495	1,415	720	2,864	2,027	2,581	2,454	2,564	2,385	25,773
EFFICIENCY PROGRAMS SUBTOTAL	50	69	299	981	2,055	3,019	3,425	1,316	1,435	2,311	1,347	778	1,681	2,095	3,946	7,254	12,388	12,929	13,817	13,758	14,564	13,528	11,165	12,020	136,232
CUSTOMER SELF-GENERATION PROGRAMS																									
Bioenergy Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	1,783	1,723	1,732	1,256	1,344	0	0	7,993
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	1,783	1,723	1,732	1,256	1,344	0	0	7,993
RATE/LOAD MANAGEMENT PROGRAMS																									
Curtailable Rates	0	0	0	0	524	1,372	1,357	1,352	1,166	1,518	1,884	2,427	3,234	4,882	6,392	6,405	7,150	6,997	6,935	6,715	6,024	5,936	5,871	5,746	83,889
	0	0	0	0	524	1,372	1,357	1,352	1,166	1,518	1,884	2,427	3,234	4,882	6,392	6,405	7,150	6,997	6,935	6,715	6,024	5,936	5,871	5,746	83,889
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Program Incentive Budgets	50	69	299	981	2,578	4,391	4,782	2,669	2,601	3,829	3,231	3,206	4,915	6,977	10,338	13,659	19,693	21,710	22,475	22,206	21,844	20,809	17,037	17,766	228,114

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund expenditures.
** Programs comprise the Commercial Building Envelope Program.

Appendix N

Natural Gas Incentive-Based Utility, Administration and Incentive Costs

Total Power Smart Utility Costs - Including Affordable Energy Costs (1000s in 2012$)
Natural Gas Incentive-Based Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL													
Affordable Energy Program*	0	0	0	0	84	0	173	494	1,624	4,611	5,096	5,441	17,521
Home Insulation	0	0	0	0	402	1,958	3,138	2,896	3,080	2,309	2,138	1,411	17,331
Water & Energy Saver	0	0	0	0	0	0	0	0	42	710	1,041	775	2,568
	0	0	0	0	485	1,958	3,311	3,390	4,746	7,630	8,274	7,627	37,420
DISCONTINUED/COMPLETED													
New Homes	0	13	80	98	65	99	146	0	91	112	65	5	774
Thermostats	0	0	0	0	0	205	138	40	1	0	0	0	384
HE Gas Furnace	0	0	0	0	620	1,404	2,235	3,333	1,601	32	0	0	9,225
	0	13	80	98	686	1,708	2,519	3,374	1,693	144	65	5	10,384
RESIDENTIAL EXPLORATORY PROGRAMS													
Residential Solar	0	0	0	0	0	0	0	0	0	8	8	0	16
RESIDENTIAL TOTAL	0	13	80	98	1,171	3,667	5,830	6,764	6,438	7,781	8,347	7,632	47,820
COMMERCIAL													
HVAC	0	0	0	0	111	644	1,745	1,452	1,171	1,270	930	1,215	8,538
Commercial Insulation**	0	0	0	0	0	446	869	1,064	1,299	2,283	1,780	1,108	8,849
New Buildings	0	0	0	0	0	0	0	150	113	200	202	1,043	1,708
Commercial Windows**	0	0	0	0	0	136	296	486	815	1,032	1,110	796	4,672
Commercial Custom	0	0	0	0	0	0	0	0	146	159	161	505	971
Commercial Building Optimization	0	0	0	0	81	243	166	166	245	212	120	92	1,325
Commercial Kitchen Appliances	0	0	0	0	0	0	0	17	57	30	48	27	180
City of Winnipeg Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	192	1,470	3,077	3,335	3,846	5,186	4,350	4,785	26,242
DISCONTINUED/COMPLETED													
Power Smart Energy Manager	0	0	0	0	0	0	125	99	74	0	52	0	351
Spray Valves	0	0	0	0	0	136	58	128	28	21	1	0	374
Commercial Hot Water	0	0	0	0	0	0	0	0	23	32	14	0	70
Power Smart Shops	0	0	0	0	0	0	1	16	84	98	12	0	211
	0	0	0	0	0	136	184	243	209	151	80	1	1,005
COMMERCIAL EXPLORATORY PROGRAMS													
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	4	11	0	15
	0	0	0	0	0	0	0	0	0	4	11	0	15
COMMERCIAL TOTAL	0	0	0	0	192	1,606	3,261	3,579	4,055	5,342	4,441	4,786	27,262
INDUSTRIAL													
Industrial Natural Gas Optimization	0	0	0	0	109	39	305	351	625	725	718	753	3,625
INDUSTRIAL TOTAL	0	0	0	0	109	39	305	351	625	725	718	753	3,625
EFFICIENCY PROGRAMS SUBTOTAL	0	13	80	98	1,472	5,312	9,396	10,694	11,118	13,848	13,506	13,171	78,706
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	0	0	0	0	0	0	14	8	0	0	0	0	22
	0	0	0	0	0	0	14	8	0	0	0	0	22
PROGRAMS SUBTOTAL	0	13	80	98	1,472	5,312	9,410	10,702	11,118	13,848	13,506	13,171	78,729
Support Costs***	1,044	712	656	953	1,395	2,700	2,139	2,047	2,087	1,428	1,835	1,421	18,416
UTILITY COST OF PROGRAMS	1,044	725	736	1,051	2,866	8,012	11,549	12,749	13,205	15,276	15,341	14,591	97,145

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund and Lower Income Furnace Replacement expenditures.
** Programs comprise the Commercial Building Envelope Program.
*** Support Costs include Affordable Energy Fund spending.

Administration Cost (1000s in 2012$)
Natural Gas Incentive-Based Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL													
Affordable Energy Program*	0	0	0	0	84	0	149	136	192	4,269	4,564	5,025	14,418
Water & Energy Saver	0	0	0	0	0	0	0	0	42	131	604	728	1,505
Home Insulation	0	0	0	0	182	560	805	628	493	516	527	184	3,895
	0	0	0	0	266	560	953	764	727	4,916	5,695	5,937	19,817
DISCONTINUED/COMPLETED													
New Homes	0	13	80	80	22	33	52	0	16	0	17	1	314
HE Gas Furnace	0	0	0	0	280	307	473	374	204	17	0	0	1,656
Thermostats	0	0	0	0	0	117	100	19	1	0	0	0	236
	0	13	80	80	302	457	625	393	221	17	17	1	2,206
RESIDENTIAL EXPLORATORY PROGRAMS													
Residential Solar	0	0	0	0	0	0	0	0	0	8	8	0	16
RESIDENTIAL TOTAL	0	13	80	80	568	1,018	1,578	1,157	947	4,941	5,720	5,938	22,040
COMMERCIAL													
New Buildings	0	0	0	0	0	0	0	150	113	124	127	336	850
HVAC	0	0	0	0	111	301	313	264	363	270	292	326	2,240
Commercial Insulation**	0	0	0	0	0	79	80	182	184	227	274	114	1,140
Commercial Windows**	0	0	0	0	0	87	90	128	147	174	176	98	901
Commercial Custom	0	0	0	0	0	0	0	0	60	62	93	94	309
Commercial Building Optimization	0	0	0	0	81	243	166	122	161	158	81	68	1,081
Commercial Kitchen Appliances	0	0	0	0	0	0	0	8	24	11	28	19	91
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0
City of Winnipeg Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	192	710	649	855	1,052	1,026	1,071	1,057	6,612
DISCONTINUED/COMPLETED													
Power Smart Energy Manager	0	0	0	0	0	0	125	97	74	0	52	0	348
Power Smart Shops	0	0	0	0	0	0	1	16	83	96	12	0	208
Spray Valves	0	0	0	0	0	56	32	27	18	3	1	0	137
Commercial Hot Water	0	0	0	0	0	0	0	0	23	32	14	0	69
	0	0	0	0	0	56	159	140	199	130	80	0	763
COMMERCIAL EXPLORATORY PROGRAMS													
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	0	11	0	11
	0	0	0	0	0	0	0	0	0	0	11	0	11
COMMERCIAL TOTAL	0	0	0	0	192	766	808	995	1,250	1,156	1,162	1,057	7,385
INDUSTRIAL													
Industrial Natural Gas Optimization	0	0	0	0	109	39	97	92	173	122	175	244	1,050
	0	0	0	0	109	39	97	92	173	122	175	244	1,050
EFFICIENCY PROGRAMS SUBTOTAL	0	13	80	80	869	1,823	2,484	2,243	2,370	6,218	7,057	7,239	30,475
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	0	0	0	0	0	0	14	8	0	0	0	0	22
	0	0	0	0	0	0	14	8	0	0	0	0	22
PROGRAMS SUBTOTAL	0	13	80	80	869	1,823	2,498	2,251	2,370	6,218	7,057	7,239	30,497
Support Costs***	1,044	712	656	953	1,395	2,700	2,139	2,047	2,087	1,428	1,835	1,421	18,416
ADMINISTRATION COSTS OF PROGRAMS	1,044	725	736	1,034	2,263	4,522	4,637	4,298	4,457	7,646	8,892	8,659	48,913

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund and Lower Income Furnace Replacement expenditures.
** Programs comprise the Commercial Building Envelope Program.
*** Support Costs include Affordable Energy Fund spending.

Incentive Costs (1000s in 2012$)
Natural Gas Incentive-Based Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL													
Home Insulation	0	0	0	0	219	1,398	2,334	2,269	2,587	1,793	1,611	1,226	13,436
Affordable Energy Program*	0	0	0	0	0	0	24	358	1,432	342	532	416	3,104
Water & Energy Saver	0	0	0	0	0	0	0	0	0	579	436	311	1,326
	0	0	0	0	219	1,398	2,358	2,627	4,019	2,714	2,579	1,953	17,866
DISCONTINUED/COMPLETED													
New Homes	0	0	0	18	43	67	94	0	75	112	48	4	460
HE Gas Furnace	0	0	0	0	340	1,096	1,761	2,959	1,397	14	0	0	7,569
Thermostats	0	0	0	0	0	88	38	21	0	0	0	0	148
	0	0	0	18	384	1,251	1,894	2,980	1,472	127	48	4	8,177
RESIDENTIAL EXPLORATORY PROGRAMS													
Residential Solar	0	0	0	0	0	0	0	0	0	0	0	0	0
RESIDENTIAL TOTAL	0	0	0	18	603	2,649	4,251	5,607	5,491	2,841	2,627	1,957	26,044
COMMERCIAL													
Commercial Insulation**	0	0	0	0	0	367	790	882	1,116	2,056	1,506	993	7,709
HVAC	0	0	0	0	0	343	1,432	1,188	808	1,000	638	889	6,299
New Buildings	0	0	0	0	0	0	0	0	0	76	75	707	858
Commercial Windows**	0	0	0	0	0	50	206	358	668	858	934	701	3,774
Commercial Custom	0	0	0	0	0	0	0	0	86	98	67	410	661
Commercial Building Optimization	0	0	0	0	0	0	0	44	83	54	39	24	243
Commercial Kitchen Appliances	0	0	0	0	0	0	0	8	33	19	20	8	89
City of Winnipeg Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	760	2,428	2,480	2,794	4,160	3,279	3,733	19,634
DISCONTINUED/COMPLETED													
Spray Valves	0	0	0	0	0	81	26	101	10	19	0	0	236
Power Smart Shops	0	0	0	0	0	0	0	0	1	2	0	0	3
Power Smart Energy Manager	0	0	0	0	0	0	0	2	0	0	0	0	2
Commercial Hot Water	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	81	26	104	11	21	0	0	242
COMMERCIAL EXPLORATORY PROGRAMS													
Heat Recovery Ventilation Program	0	0	0	0	0	0	0	0	0	4	0	0	4
	0	0	0	0	0	0	0	0	0	4	0	0	4
COMMERCIAL TOTAL	0	0	0	0	0	840	2,453	2,584	2,805	4,186	3,279	3,733	19,880
INDUSTRIAL													
Industrial Natural Gas Optimization	0	0	0	0	0	0	208	260	452	603	543	509	2,575
	0	0	0	0	0	0	208	260	452	603	543	509	2,575
EFFICIENCY PROGRAMS SUBTOTAL	0	0	0	18	603	3,489	6,912	8,451	8,748	7,630	6,449	6,199	48,499
CUSTOMER SELF-GENERATION													
Bioenergy Optimization	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0
PROGRAMS SUBTOTAL	0	0	0	18	603	3,489	6,912	8,451	8,748	7,630	6,449	6,199	48,499
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
ADMINISTRATION COSTS OF PROGRAMS	0	0	0	18	603	3,489	6,912	8,451	8,748	7,630	6,449	6,199	48,499

Note: Subtotals may not be exact due to rounding.
* Includes Affordable Energy Fund and Lower Income Furnace Replacement expenditures.
** Programs comprise the Commercial Building Envelope Program.

Appendix O

Electric DSM Support Programs - Utility Costs

Utility Costs (1000s in 2012$)
Electric DSM Support Programs

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL														
Residential Pays	-	-	-	-	-	-	-	-	-	-	-	27	229	256
Power Smart Residential Loan	47	80	21	9	(0)	1	10	(1)	(6)	(76)	(38)	(29)	125	141
Solar Hot Water Heating	-	-	-	-	-	-	-	-	0	7	-	-	-	7
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ecoENERGY	-	-	-	-	(11)	(44)	74	171	(20)	148	104	114	(29)	507
Residential Earth Power Loan	-	2	49	101	359	912	(96)	74	216	168	106	86	(72)	1,905
COMMERICAL														
Commercial Pays	-	-	-	-	-	-	-	-	-	-	-	-	123	123
DSM SUPPORT PROGRAMS SUBTOTAL	47	82	69	110	348	869	(12)	243	190	246	172	199	376	2,939

Note: Subtotals may not be exact due to rounding.

Utility Costs for Support, Basic Information Services, DSM Support Programs & Standards (1000s in 2012$)
Electric DSM Support Programs

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
DSM SUPPORT PROGRAMS																									
DSM Support Programs & Standards	-	-	-	-	-	-	-	-	-	-	-	47	82	69	110	348	869	(12)	243	190	246	172	199	376	2,939
BASIC INFORMATION SERVICES																									
Basic Information Services	-	-	14	6	96	57	11	13	164	495	584	1,350	1,373	1,365	1,743	1,655	1,671	1,359	1,356	1,773	1,761	1,422	1,476	1,342	21,087
Discontinued/Completed Basic Information Services	-	-	-	-	5	23	166	146	1	77	262	323	420	309	392	449	405	11	(4)	-	-	1	0	-	2,987
SUPPORT COSTS																									
Power Smart Communications	-	9	730	1,562	1,112	544	718	677	592	512	727	651	181	530	484	939	644	615	643	1,174	897	822	791	666	16,220
DSM Administration	-	216	220	186	136	99	121	193	75	41	105	136	194	317	217	247	217	218	166	258	215	227	290	178	4,272
Sustainability & Standards	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51	87	50	58	198	172	134	164	913
Power Smart Residential Support	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29	55	67	141	292
Integrated Plans/Targets	-	20	496	245	223	215	218	66	33	85	168	100	37	376	279	73	24	97	95	180	266	172	213	127	3,808
Power Smart for Business	-	-	-	146	144	91	52	0	-	-	-	-	-	-	-	-	88	162	221	207	205	164	191	115	1,785
DSM Market Potential Study	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	96	246
DSM Tracking System	-	-	-	14	23	149	155	13	1	1	3	-	-	-	-	-	-	3	7	1	20	83	81	86	641
Energy Efficient Screening Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	36	50	31	129
Commercial Audits	-	-	-	-	-	-	-	-	-	-	-	-	17	23	21	31	40	5	2	-	0	0	1	14	155
Alternative Geothermal Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	1	26
Residential Earth Power Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	2	0	9
Residential Retrofit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	45	35	130	76	86	53	61	0	499
Retrofit Demonstrations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	5	2	1	-	-	-	50
Discontinued/Completed Support Costs	-	-	988	835	440	53	56	124	133	101	62	78	160	203	46	14	8	0	-	-	-	-	-	-	3,301
	-	245	2,433	2,988	2,078	1,151	1,320	1,074	834	741	1,065	965	589	1,449	1,047	1,317	1,159	1,223	1,319	1,954	1,931	1,790	2,056	1,618	32,346
TOTAL SUPPORT/DSM SUPPORT PROGRAMS/STANDARDS	-	245	2,447	2,995	2,179	1,231	1,498	1,233	998	1,313	1,911	2,685	2,464	3,192	3,292	3,770	4,104	2,580	2,913	3,918	3,938	3,385	3,731	3,336	59,358

Note: Subtotals may not be exact due to rounding.

Appendix P

Natural Gas DSM Support Programs - Utility Costs

Utility Costs (1000s in 2012$)
Natural Gas DSM Support Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
RESIDENTIAL													
Residential Pays	-	-	-	-	-	-	-	-	-	-	18	425	443
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	37	53	90
Solar Hot Water Heating	-	-	-	-	-	-	-	0	2	-	-	-	2
R-2000 Component of the New Home Program	-	-	-	-	-	-	-	-	-	-	-	-	-
ecoENERGY	259	300	302	362	(10)	666	512	(113)	591	395	477	(116)	3,626
Power Smart Residential Loan	451	117	52	(5)	16	187	(23)	(113)	(685)	(726)	(554)	(646)	(1,930)
COMMERCIAL													
Commercial Pays	-	-	-	-	-	-	-	-	-	-	-	151	151
DSM SUPPORT PROGRAMS SUBTOTAL	710	416	355	357	5	854	488	(226)	(92)	(331)	(22)	(133)	2,382

Note: Subtotals may not be exact due to rounding.

Utility Costs for Support, Basic Information Services, DSM Support Programs & Standards (1000s in 2012$)
Natural Gas DSM Support Programs

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	Cumulative Total 2012/13
DSM Support Programs													
DSM Support Programs & Standards	710	416	355	357	5	854	488	(226)	(92)	(331)	(22)	(133)	2,382
	710	416	355	357	5	854	488	(226)	(92)	(331)	(22)	(133)	2,382
BASIC INFORMATION SERVICES													
Basic Information Services	181	205	224	506	535	696	480	536	505	376	323	20	4,587
	181	205	224	506	535	696	480	536	505	376	323	20	4,587
Discontinued/Completed Basic Information Services	-	-	-	-	4	27	(10)	-	-	-	-	-	21
	-	-	-	-	4	27	(10)	-	-	-	-	-	21
SUPPORT COSTS													
Power Smart Communications	-	-	-	-	347	410	429	960	734	548	527	545	4,500
Power Smart Residential Support	-	-	-	-	-	-	-	-	44	82	100	262	488
DSM Administration	-	-	-	-	145	145	111	211	176	152	193	145	1,278
Power Smart for Business	-	-	-	-	-	108	147	138	136	164	128	140	961
Sustainability & Standards	-	-	-	-	86	160	93	107	162	115	89	136	947
Integrated Plans/Targets	-	-	-	-	75	65	63	147	217	115	142	104	928
DSM Market Potential Study	-	-	-	-	-	-	-	-	-	-	149	79	228
DSM Tracking System	-	-	-	-	-	2	4	1	16	55	54	71	203
Energy Efficient Screening Studies	-	-	-	-	-	-	-	-	9	36	33	37	115
Commercial Audits	-	-	-	-	17	20	10	-	1	1	4	14	68
Residential Retrofit	-	-	-	-	-	65	241	142	160	99	113	0	819
Retrofit Demonstrations	-	-	-	-	78	-	5	-	-	-	-	-	83
Discontinued/Completed Support Costs	-	-	-	-	-	0	-	-	-	-	-	-	0
	-	-	-	-	748	976	1,103	1,705	1,656	1,366	1,533	1,533	10,620
TOTAL SUPPORT COSTS & DSM SUPPORT PROGRAMS & STANDARDS	892	622	579	863	1,293	2,552	2,060	2,015	2,069	1,410	1,835	1,421	17,609

Note: Subtotals may not be exact due to rounding.

MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

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ENERGY SUPPLY

9.0 OVERVIEW

Tab 9 provides information on energy supply planning as well as an estimate of energy generation based on prevailing water conditions. Section 9.1 provides highlights of the Manitoba Hydro system; Section 9.2 describes Manitoba Hydro's criteria that are utilized to ensure an adequate supply of capacity and dependable energy; Section 9.3 provides supply and demand tables that summarize the capacity and dependable energy for each year up to 2023/24; Section 9.4 provides information on the following major projects and initiatives: Keeyask GS, Manitoba-Minnesota Transmission Project, Bipole III transmission, Demand Side Management, and Pointe du Bois GS; Section 9.5 provides a description of export market conditions and Manitoba Hydro's export sales activities; Section 9.6 provides an update on water conditions and hydraulic generation based on recent water conditions; and, Section 9.7 provides information related to the loss of revenues due to the risk of an extended drought period commencing in 2016/17 with a duration of five years.

The key observations with respect to Tab 9 are:

1. Manitoba Hydro's MH14 is forecast based on expected water flows for the first year of the forecast (2014/15), median water flows for the second year of the forecast (2015/16), and the average revenues for all water flow conditions for the past 102 years for the subsequent years of the forecast (2016/17 and thereafter).

2. In the near-term, to 2016/17, projected net income from electric operations (including the proposed rate increases) is higher in MH14 as compared to MH13, largely due to favourable water flow conditions and lower finance and depreciation expense.

3. Although inflow conditions are currently favourable and there is confidence that these conditions will persist until the end of March 2015, inflow conditions in fiscal 2015/16 are very uncertain and can be quite different from those assumed in MH14. The main factor that determines water supply conditions in 2015/16 is precipitation, which is highly variable and unknown at this time. The MH14

assumes median inflows in 2015/16 which means that there is an equal probability that inflows will be higher or lower.

4. Manitoba Hydro's financial results are subject to extreme volatility based on potential changes in water flow conditions. Actual water flows and the associated financial impacts will deviate either up or down from the assumption of average. In order to maintain the 3.95% indicative annual rate increases over the long-term, it is necessary that the financial impacts of low and high water flows balance out over time.

5. The reduction in hydroelectric energy supply during periods of extended low flow conditions can have a significant negative impact on Manitoba Hydro's financial situation. A repeat of a recent historic five-year drought (1987/88 to 1992/93) starting in 2016/17 is projected to decrease the net revenue by $1.7 billion up to the year 2020/21, including finance costs. There is a significant risk that this estimate could be greater if a series of adverse conditions occurred coincident with this time period, including higher natural gas prices and import prices, or a more severe drought spanning seven-years from 2016/17 to 2022/23, (1936/37 to 1942/43), increases the cost of drought to $2.1 billion under expected market prices.

6. To ensure rate stability for customers, Manitoba Hydro's desired approach is to implement regular and reasonable rate increases, even during periods of favourable water flows, thereby balancing the inevitable years of less favourable than forecast results where water flows are below average.

In accordance with the filing requirements of Directive 5 of Order 43/13, Appendix 9.1 provides monthly hydraulic generation information, water conditions and extra-provincial energy exchange data for the months of April 2014 to December 2014. Manitoba Hydro will provide this information for January to March 2015 on a monthly basis when available.

9.1 ENERGY SUPPLY

The existing supply of power available to meet Manitoba load requirements is comprised of generating resources currently available within Manitoba and imports from neighboring U.S. utilities. Consistent with Provincial approvals stemming from the Needs For and Alternatives to (NFAT) process and environmental regulatory approvals, Keeyask G.S. and a new 500 kV US interconnection are included in the Integrated Financial Forecast (IFF14). As was previously noted in the filing, Conawapa Generating Station has been suspended for purposes of the IFF14.

IFF14 includes a number of other major projects that are required for system reliability and for transmitting existing and future northern generation.

9.2 POWER RESOURCE PLANNING CRITERIA

In planning for a reliable supply of electric power, Manitoba Hydro has established the following criteria to ensure an adequate supply of capacity and energy for Manitoba. The current generation planning criteria is the same as used in the Needs For and Alternatives To submission.

The generation planning criteria consist of two components, both of which must be satisfied. First, there is a capacity criterion, used to determine the minimum quantity of generation capacity required. Second, there is an energy criterion, used to determine the minimum quantity of energy required. These two criteria are outlined in the following sections.

9.2.1 Capacity Criterion

Manitoba Hydro's capacity criterion requires that the Corporation plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time.

The reserve is intended to protect against capacity shortfalls resulting from breakdown of generation equipment, or increases in winter peak load due extreme weather conditions. The reserve is calculated as 12% of the Manitoba forecast peak winter demand plus the reserve required by any export contract in effect at the time for each year that is forecasted. The maximum demand for capacity in Manitoba occurs in the winter season, and therefore the reserve margin of 12% is applied to the winter peak demand.

Historically, the reserve margin of 12% has been adequate for Manitoba Hydro's predominantly hydro-electric generation based system because of relatively low outage rates combined with the relatively small size of hydro-generating units. In comparison, reserve margins in predominantly thermal generation based systems are typically in the 15% range, when expressed on an installed capacity basis.

9.2.2 Energy Criterion

In addition to a capacity criterion, Manitoba Hydro has an energy criterion which recognizes the energy-constrained limitation of a hydro-electric generating system during drought conditions.

Manitoba Hydro’s energy criterion requires that the corporation plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated; the energy supply under these conditions is referred to as dependable energy.

Historic system inflows are derived from the available record of river flows (1912-2013), which have been adjusted to represent present-use conditions and to account for systemic changes due to expected future water use and withdrawals upstream of Manitoba.

Dependable energy available in the Manitoba Hydro system is the total energy supplied from:

- hydro-electric generating stations
- thermal generating stations
- wind generation (energy only)
- planned DSM
- imports from neighbouring utilities.

9.3 SUPPLY AND DEMAND SUMMARY

A summary of the firm electric supply and demand during the winter peak (MW) for the Manitoba system between fiscal years 2014/15 and 2023/24 is provided in Figure 9.1. Demand includes the 2014 forecast of Manitoba load plus contracted extra provincial exports and capacity reserve requirements. Figure 9.2 provides a similar summary for firm energy (GWh) supply and demand during each year for the 10 year period. Figure 9.3 reflects the supply and demand for energy (GWh) for expected flow conditions for 2014/15, median flow conditions for 2015/16 and the average of all flow conditions for 2016/17 to 2023/24.

Figure 9.1: System Firm Winter Peak Demand and Capacity Resources (MW) @ generation

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
	Manitoba Hydro Power Resources											
	New Hydro											
	Keeyask G.S.							90	630	630	630	630
	Total New Hydro							90	630	630	630	630
	New NUG Purchase				12	12	12	12	12	12	12	12
1	**Total New Power Resources**				**12**	**12**	**12**	**102**	**642**	**642**	**642**	**642**
	Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167
	Existing Thermal											
	Brandon Unit 5		105	105	105	105	105					
	Selkirk Gas			66	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280
	Total Existing Thermal		385	451	517	517	517	412	412	412	412	412
	Imports		605	605	605	605	605	605	605	605	605	605
	Bipole III Line Reduction						90	90	80	80	80	80
2	**Total Base Supply Power Resources**		**6 123**	**6 228**	**6 286**	**6 312**	**6 407**	**6 303**	**6 278**	**6 269**	**6 264**	**6 264**
3	**Total Power Resources**	**1+2**	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**
	Peak Demand											
	2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400
	Less: 2014 Base DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498
4	**Manitoba Net Load**		**4 656**	**4 692**	**4 692**	**4 759**	**4 775**	**4 813**	**4 817**	**4 835**	**4 867**	**4 902**
	Contracted Exports		726	484	724	724	559	559	779	908	880	880
	Proposed Exports											
5	**Total Exports**		**726**	**484**	**724**	**724**	**559**	**559**	**779**	**908**	**880**	**880**
6	**Total Peak Demand**	**4+5**	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**
7	Reserves		513	563	563	571	573	577	578	580	584	588
	System Surplus	**3-6-7**	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**

Figure 9.2: System Firm Energy Demand and Dependable Resources (GWh) @ generation

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
	Manitoba Hydro Power Resources											
	New Hydro											
	Keeyask							493	2 974	3 003	3 003	3 003
	Total New Hydro							493	2 974	3 003	3 003	3 003
	New NUG Purchase				97	97	97	97	97	97	97	97
1	**Total New Power Resources**				**97**	**97**	**97**	**590**	**3 071**	**3 100**	**3 100**	**3 100**
	Existing Hydro		21 928	21 924	21 892	21 878	21 880	21 863	21 816	21 775	21 743	21 743
	Existing Thermal											
	Brandon Unit 5		811	811	811	811	811	592				
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Total Existing Thermal		4 118	4 118	4 118	4 118	4 118	3 899	3 307	3 307	3 307	3 307
	Imports		3 440	3 852	3 912	3 912	3 912	3 912	5 304	5 582	5 582	5 582
	Existing Wind		771	771	771	771	771	771	771	771	771	771
	Bipole III Reduced Losses						101	101	177	177	177	177
2	**Total Base Supply Power Resources**		**30 257**	**30 665**	**30 693**	**30 679**	**30 782**	**30 546**	**31 375**	**31 612**	**31 580**	31 580
3	**Total Power Resources**	**1+2**	**30 257**	**30 665**	**30 790**	**30 776**	**30 878**	**31 136**	**34 446**	**34 711**	**34 680**	**34 680**
	Demand											
	2014 Base Load Forecast		25 639	26 130	26 436	27 174	27 662	28 247	28 583	28 937	29 284	29 626
	Construction Power - Hydro			110	110	110	110	110	83			
	Less: 2014 Base DSM Forecast		- 283	- 487	- 780	-1 056	-1 407	-1 730	-1 988	-2 183	-2 296	-2 405
4	**Net Load**		**25 356**	**25 753**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 754**	**26 988**	**27 221**
	Contracted Exports		3 421	2 632	3 246	3 366	3 165	3 125	3 951	4 603	4 503	4 476
	Proposed Exports											
	Less: Total Adverse Water			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 513	- 513
5	**Total Net Exports**		**3 421**	**2 323**	**2 876**	**2 995**	**2 795**	**2 754**	**3 580**	**4 114**	**3 990**	**3 963**
6	**Total Demand**	**4+5**	**28 776**	**28 076**	**28 642**	**29 224**	**29 160**	**29 381**	**30 258**	**30 868**	**30 978**	**31 184**
	System Surplus	**3-6**	**1 481**	**2 589**	**2 148**	**1 552**	**1 718**	**1 754**	**4 187**	**3 843**	**3 702**	**3 496**

Figure 9.3: System Firm Energy Demand and Resources (GWh) @ generation
2014/15 Expected Water Flow Conditions
2015/16 Median Water Flow Conditions
2016/17 -2023/24 Average of All Flow Conditions

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
	Manitoba Hydro Power Resources											
	Hydro Generation		35 116	34 418	31 084	31 129	30 907	31 456	34 535	35 275	35 251	35 253
	Bipole III Reduced Losses						324	324	352	352	352	352
	Thermal Generation		101	121	358	383	385	328	166	156	162	154
	Existing Wind		918	898	907	907	907	907	907	907	907	907
	New NUG Purchase				97	97	97	97	97	97	97	97
	Imports		180	328	1 355	1 441	1 445	1 392	1 861	2 042	2 109	2 119
1	**Total Power Resources**		**36 315**	**35 765**	**33 800**	**33 956**	**34 064**	**34 503**	**37 917**	**38 828**	**38 877**	**38 881**
	Demand											
	2014 Base Load Forecast		25 321	25 754	26 436	27 174	27 662	28 247	28 583	28 937	29 284	29 626
	Construction Power - Hydro				110	110	110	110	83			
	Less: 2014 Base DSM Forecast		- 305	- 415	- 780	-1 056	-1 407	-1 730	-1 988	-2 183	-2 296	-2 405
2	**Net Load**		**25 016**	**25 339**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 754**	**26 988**	**27 221**
3	Contracted Exports		4 537	4 051	3 406	3 438	3 232	3 192	4 474	5 343	5 278	5 251
4	**Total Demand**	**2+3**	**29 553**	**29 390**	**29 172**	**29 667**	**29 598**	**29 819**	**31 153**	**32 097**	**32 266**	**32 472**
	System Surplus	**1-4**	**6 762**	**6 375**	**4 628**	**4 290**	**4 466**	**4 684**	**6 764**	**6 731**	**6 611**	**6 409**

9.4 MAJOR PROJECTS

IFF14 includes several major projects to which Manitoba Hydro has committed or for which there is a reasonable expectation that Manitoba Hydro will commit. The characteristics of these initiatives are summarized below.

Keeyask Generation Project

On May 7, 2014 the Minister of Conservation and Water Stewardship released the Manitoba Clean Environment Commission's ("CEC") report on the Keeyask Generation Project, recommending that the project be issued a licence under the Manitoba Environment Act.

The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership. On July 16, 2014 construction began on the Keeyask Generating Station with a planned first unit in-service date in 2019. Keeyask is located upstream of the Kettle Generating Station on the Nelson River with a design rating of 695 MW under ideal operating conditions and a winter peak rating of 630 MW which is utilized for planning purposes.

Manitoba – Minnesota Transmission Project

The Manitoba – Minnesota Transmission Project is a 500 kV AC transmission line in southeastern Manitoba, connecting at the border with Minnesota Power's proposed Great Northern Transmission Line. The Manitoba – Minnesota Transmission Project will enable power to be exported to the United States based on current sales agreements, improve reliability and import capacity in emergency and drought situations, and increase access to markets in the US. The projected in-service date is 2020/21. The project requires several Canadian and US regulatory approvals which are expected to be received by late 2016.

Bipole III Reliability Project

Based on recommendations from the Clean Environment Commission, Manitoba Conservation and Water Stewardship granted an Environment Act licence to Manitoba Hydro on August 14, 2013 for the construction, operation, and maintenance of the Bipole III Project. Construction began in fall 2013. The project has a planned in-service date of 2018/19.

Demand Side Management

The Demand Side Management Programs (DSM) targets a 1,652 MW reduction in peak load and a 6,344 GWh reduction in annual energy consumption by 2028/29, which reflects a minor upward adjustment to the forecast in the Power Smart Plan. As of March 31, 2014 these programs have achieved a 500 MW reduction of peak load and a 2,307 GWh reduction in annual energy consumption as at 2028/29. Savings due to the Curtailable Rate Program total 161 MW. Anticipated changes to Codes and Standards for new equipment (e.g. refrigerators, electric motors and lighting) are expected to result in reductions of 409 MW and 1,240 GWh which are reflected in Manitoba Hydro's load forecast. The remaining reduction of 582 MW and 2797 GWh is shown as a reduction to Manitoba load in the Supply and Demand Tables.

Pointe du Bois Generating Station

The Spillway Replacement Project is on schedule to be completed by summer 2015. A new spillway became operational in August 2014. Work over the next year, will include completing that the main dam and decommissioning the old spillway.

Pointe du Bois Generating Station is assumed to operate until 2039/40. The ability to extend the life of the Pointe du Bois Generating Station is currently under review.

Non-Utility Generation

Manitoba Hydro and Kineticor Resource Corporation executed a Term Sheet for the purchase of 11.65 MW of flare gas generated electricity over a 20 year term. This agreement is assumed to add 97 GWh of dependable energy to Manitoba Hydro's system.

9.5 EXPORT MARKETS AND EXPORT SALES

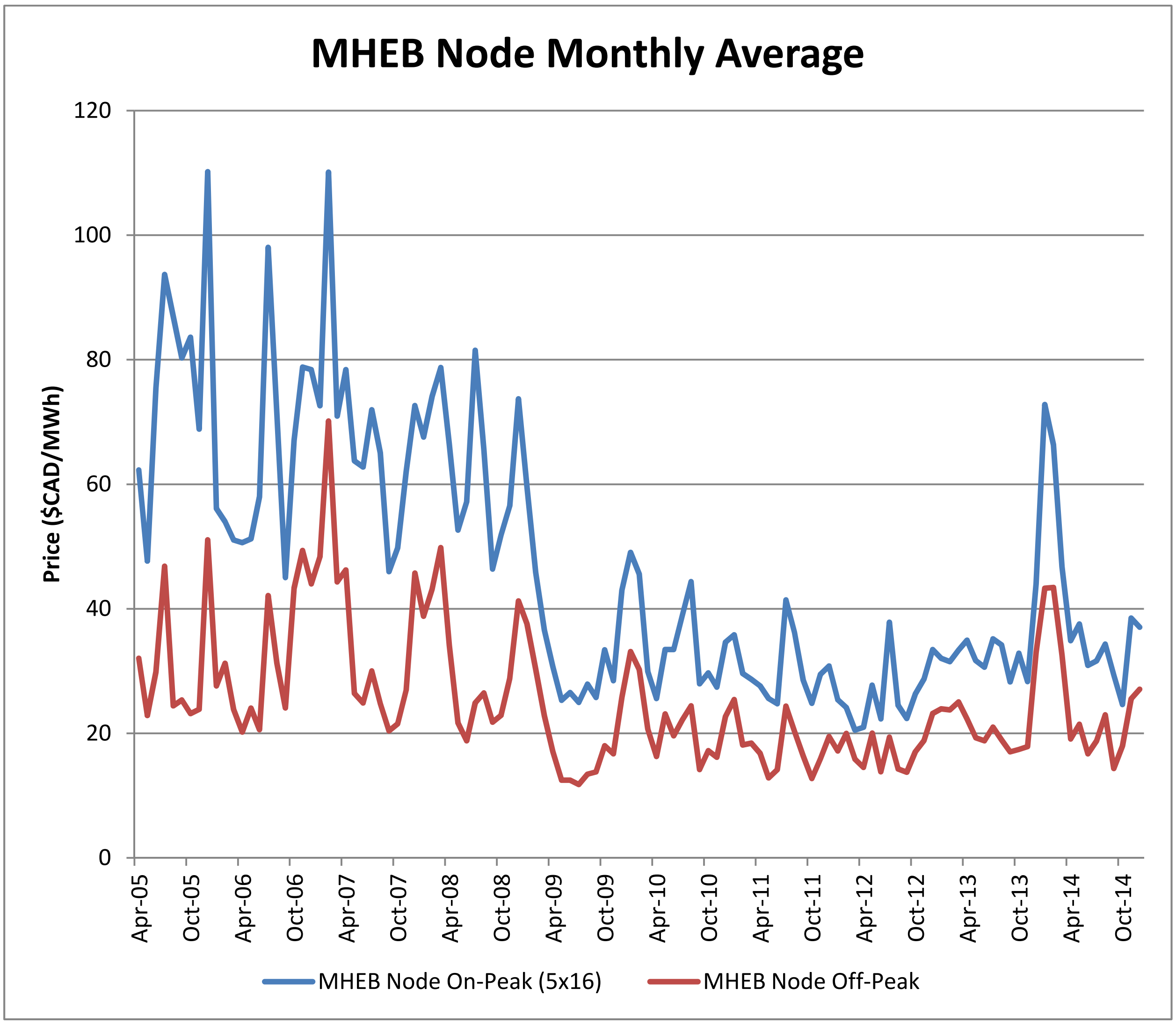
Current Market Conditions

Manitoba Hydro's U.S. export customers' load forecasts reflect modest and in some cases negative load growth. Despite relatively flat short term load forecasts that grow modestly in the mid to long-term, U.S. customer interest remains strong for long-term firm hydro power as they are focusing on replacing aging coal and nuclear generating facilities and to meet current and future emission constraints. Given President Obama's Clean Power Plan to reduce carbon emissions and more stringent environmental controls (most recently to reduce ozone levels) for existing and new coal generation, volatility and long term uncertainty of the costs for new natural gas-fired generation, and weak public support for nuclear generation, there is continued interest in long-term, fixed price, non-emitting supplies from Manitoba. Hydroelectric generation is also recognized as a complementary partner to new intermittent renewable generation resources such as wind and solar.

Saskatchewan's load growth is robust due to strong economic performance and increasing industrial loads. SaskPower is also addressing new Canadian federal regulations on the use of coal to generate electricity. Approximately 50% of their current generating capability is fueled with coal and many of these stations will need to be retired if not upgraded to expensive clean coal technology. SaskPower remains interested in diversifying their supply portfolio with additional long term purchases from Manitoba Hydro.

Prices for Manitoba Hydro's export energy increased significantly in the ten years prior to 2009 as a result of US electricity market restructuring, a general tightening of supply, and a general rise in natural gas prices. However, spot and short-term energy prices decreased by approximately 50% in 2009 primarily as a result of significantly lower natural gas prices. In addition, modest load growth since 2009, the establishment of the MISO Ancillary Services Market, and the large scale development of new wind resources in North Dakota and Minnesota have also put downward pressure on energy prices. Figure 9.4 shows the history of monthly average on-peak (5 days × 16 hours) and off-peak (balance of hours) electricity prices for the MISO Manitoba Hydro Commercial Pricing Node.

Figure 9.4 Monthly Average On-Peak and Off-peak Prices at the MHEB Commercial Pricing Node



Manitoba Hydro continues to have good access to the U.S. market operated by the MISO. Access to the US will expand with the planned in-service of the new 500 kV transmission interconnection between Manitoba and Minnesota in 2020/21. Although demand for

Manitoba Hydro's electricity is strong in Saskatchewan, current access is limited. However, Manitoba Hydro and SaskPower are considering new transmission investments should a long-term power sale agreement come to fruition.

In recent years, market access to the Ontario market has been less favourable. Operated by the Independent Electricity System Operator (IESO), recent Ontario market rule changes and interpretations of those rules, in Manitoba Hydro's opinion, place external market participants at a disadvantage relative to generators located within Ontario, and negatively impacts competition overall. These developments have reduced Manitoba Hydro's incentive to participate in the IESO market. Market rules in Ontario continue to evolve, and are designed for the benefit of the load and local generation within the market. It is a continual challenge for Manitoba Hydro to maintain non-discriminatory access to Ontario.

From an overall perspective, open transmission access in the US and open energy markets have been very beneficial to Manitoba Hydro. Expanded access to the US and Saskatchewan will provide additional export opportunities, import capability and enhance Manitoba reliability.

Manitoba Hydro's recent average pricing experience of long-term dependable sales versus on-peak (5×16) opportunity sales is depicted in Figure 9.5. As most dependable sales are for on-peak energy, the price comparison to on-peak opportunity sales is appropriate. The prices shown for dependable sales include demand charges. In several years prior to the economic downturn of 2008-09, on-peak opportunity sales prices regularly exceeded dependable prices. However this changed abruptly in the spring of 2009 as load reduced and natural gas prices decreased.

Figure 9.5 Monthly Average On-Peak Pricing (Dependable vs. Opportunity)

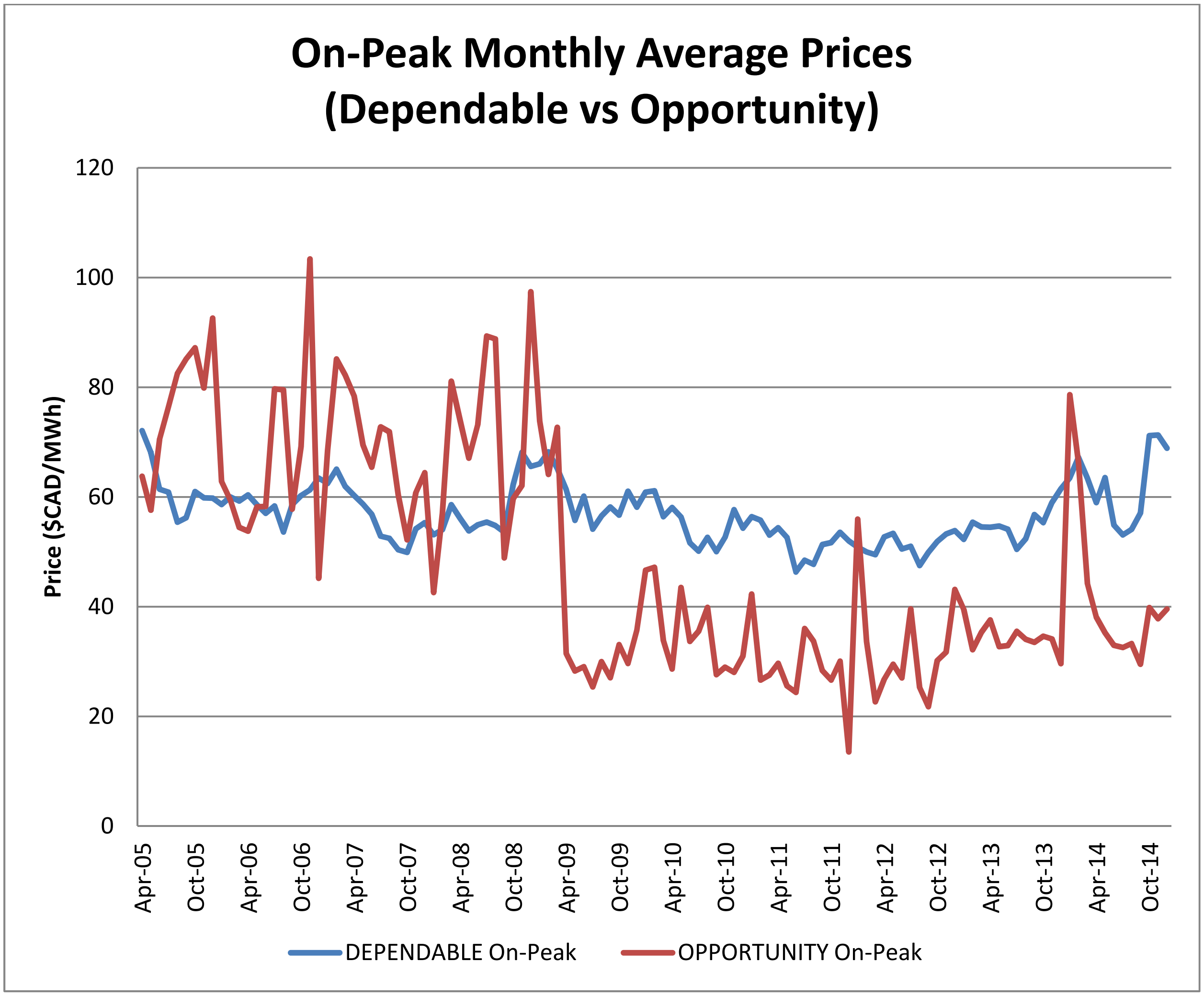


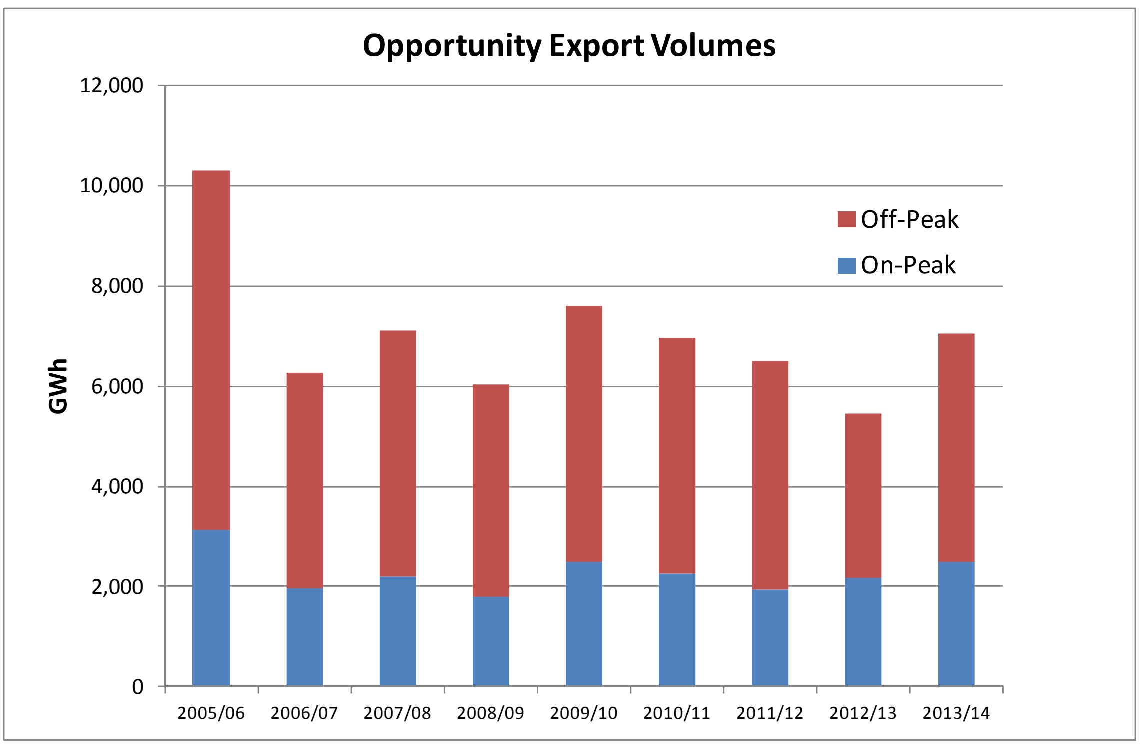
Figure 9.6 includes opportunity export volumes and average prices from the start of the MISO Day 2 Energy Market in April 2005 through December 2014. Figure 9.7 charts these opportunity export volumes for both on-peak (5×16) and off-peak periods, for the full fiscal years in this period. Opportunity export volumes are affected by water supply conditions, dependable export sales, and Manitoba load requirements. As a result, opportunity export volumes show significant variability year-to-year.

Figure 9.6 Opportunity Export Sales

OPPORTUNITY EXPORTS						
	On Peak GWh	Off Peak GWh	On Peak Avg Price (CAD$)	Off Peak Avg Price (CAD$)	On Peak Revenues (CAD $M)	Off Peak Revenues (CAD $M)
2005/06	3,142	7,161	72.73	36.75	245	265
2006/07	1,972	4,278	66.26	37.44	135	160
2007/08	2,212	4,887	66.19	32.97	162	166
2008/09	1,802	4,237	71.78	29.37	153	134
2009/10	2,497	5,100	31.14	18.74	84	100
2010/11	2,268	4,699	31.90	21.23	76	105
2011/12	1,952	4,550	28.76	22.51	59	93
2012/13	2,165	3,286	29.87	22.02	69	77
2013/14	2,492	4,566	36.95	24.46	82	121
2014/15[a]	1,789	3,878	33.33	21.70	67	92

(a) Fiscal year through December 2014.

Figure 9.7 Opportunity Export Volumes



The average price received for opportunity energy softened considerably in 2009/10 and, as shown in Figure 9.6, on-peak prices dropped more in relative and absolute terms than off-peak prices. As previously noted, spot and short-term energy prices decreased by approximately 50% in 2009 primarily as a result of significantly lower natural gas prices. In addition, modest load growth since 2009, the establishment of the MISO Ancillary Services Market, and the large scale development of new wind resources in North Dakota and Minnesota have also put downward pressure on energy prices.

Figures 9.8 and, 9.9 provide export volumes, revenues and average prices for the various export sales aggregated over all on and off-peak hours. Figure 9.8 summarizes annual total exports volumes, revenues and prices for Dependable, Opportunity and Merchant sales. Figure 9.9 shows Dependable and Opportunity Sales for the US market only.

Figure 9.8 Total Export Sales

TOTAL SALES									
	DEPENDABLE SALES			OPPORTUNITY SALES			SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	6,352	258	40.64	5,801	217	37.39	0	0	0
2001/02	6,277	322	51.65	6,022	281	46.63	0	0	0
2002/03	6,544	339	53.37	3,191	137	42.97	0	0	0
2003/04	6,231	295	48.46	735	52	48.46	11	0.5	44.43
2004/05	5,633	290	51.44	4,798	239	51.44	315	11	33.32
2005/06	4,044	240	59.25	10,303	510	47.73	919	63	60.07
2006/07	3,654	218	59.67	6,250	295	46.53	1,206	60	43.38
2007/08	3,921	209	53.22	7,099	328	44.42	1,262	72	49.17
2008/09	4,087	233	57.12	6,039	287	43.64	1,598	86	48.08
2009/10	3,263	186	56.99	7,597	184	22.98	775	26	28.29
2010/11	3,377	172	51.09	6,967	181	24.77	712	27	36.93
2011/12	3,742	175	46.79	6,502	152	22.18	436	17	31.10
2012/13	3,636	177	48.69	5,451	146	25.18	150	9	34.18
2013/14	3,479	182	52.22	7,058	203	28.92	331	34	63.32
2014/15[a]	2,569	140	54.61	5,667	159	26.92	409	14	34.24

(b) Fiscal year through December 2014.

Figure 9.9 U.S. Export Sales

TOTAL U.S. SALES									
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0
2003/04	5,245	259	49.45	507	35	69.42	0	0	0
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21
2012/13	3,636	177	48.69	4,690	113	23.62	63	2	29.92
2013/14	3,479	182	52.22	6,336	182	27.70	185	7	37.17
2014/15[a]	2,569	140	54.61	4,948	134	25.79	400	13	33.66

(a) Fiscal year through December 2014.

Long-Term Sales – New Agreements and Sales under Negotiation

Manitoba Hydro has a number of signed long-term power sales agreements, several requiring the construction of Keeyask and new transmission in Manitoba and the US. Over the past year, Manitoba Hydro has also signed several memorandum of understandings to continue discussion on new arrangements in the post-2020 timeframe both in the U.S. and Canada.

All long-term sales agreements, term sheets, memorandum of understandings and discussions are protected by confidentiality provisions and mutual non-disclosure agreements signed by Manitoba Hydro and the respective counterparty. Therefore, specific pricing and terms and conditions cannot be provided in a public forum.

Xcel Energy Power Sale Agreements

On May 27, 2010, Manitoba Hydro and Xcel Energy entered into three agreements providing for (i) the sale to Northern States Power of 375 megawatts of system power in the summer seasons and 325 megawatts of system power in the winter seasons for May 2015 through April 2025, (ii) the sale to Northern States Power of 125 megawatts of system power for May 2021 through April 2025 conditional on the construction by Manitoba Hydro of major new hydro-electric generating facilities, (iii) a 350 megawatt seasonal diversity agreement with Northern States Power where capacity and energy is exported from Manitoba in the summer months and capacity and energy (if required by Manitoba Hydro) is returned to Manitoba in the winter months for the period May 2015 through April 2025.

Minnesota Power

On May 19, 2011 Manitoba Hydro and Minnesota Power entered into two agreements providing for (i) a 250 megawatt system power sale to Minnesota Power from June 2020 to May 2035, (ii) an Energy Exchange Agreement to provide Manitoba Hydro with firm transmission service to import energy during the period June 2020 to May 2035. The 250 megawatt System Power Sale Agreement is conditional upon the construction of major new hydro-electric generating facilities and new transmission in Manitoba and the U.S.

On July 30, 2014, Manitoba Hydro and Minnesota Power signed two additional definitive agreements: (i) a 133 MW Energy Sale to commence when the new 500kV transmission line is placed in service in approximately June, 2020 and continue until 2040; and (ii) a 2014 Energy Exchange Agreement to commence when the new 500kV transmission line is placed in-service and continues until 2040. These agreements provide Manitoba Hydro the right to export or import up to 133 MWh per hour of energy from Minnesota Power at Manitoba Hydro's sole discretion on the new 500 kV interconnection.

Wisconsin Public Service

On May 19, 2011, Manitoba Hydro and Wisconsin Public Service entered a contract providing for the sale of 100 MW of System Power during the period June 2021 to May 2027, dependant on the construction of Keeyask.

On February 26, 2014 Wisconsin Public Service and Manitoba Hydro entered into the following four definitive agreements:

(a) A 308 MW System Power Sale Agreement for 10 years beginning with the fourth unit of the Conawapa Generating Station going into service. The sale is dependent upon construction of the Conawapa generating station and a new 500 kV interconnection to the US.

(b) A 108 MW System Power Sale Agreement for the five year period June 2016 through May 2021. The capacity and dependable energy supporting this agreement do not require the construction of any new generation or transmission facilities.

(c) A 200 MW Energy Purchase Agreement for the period June 2020 through May 2036. The agreement is conditional upon the construction of the new 500 kV interconnection to the US, and will utilize 200 MW of the 698 MW of additional import capability provided by the transmission line.

(d) An 8 MW Energy Sale Agreement for the period June 2023 through May 2029. The 8 MW Energy Sale Agreement in conjunction with the 100 MW System Power Sale Agreement signed on May 19, 2011 for the same period utilizes all of the existing 108 MW of firm transmission service that is available between Manitoba Hydro and Wisconsin Public Service.

9.6 WATER CONDITIONS

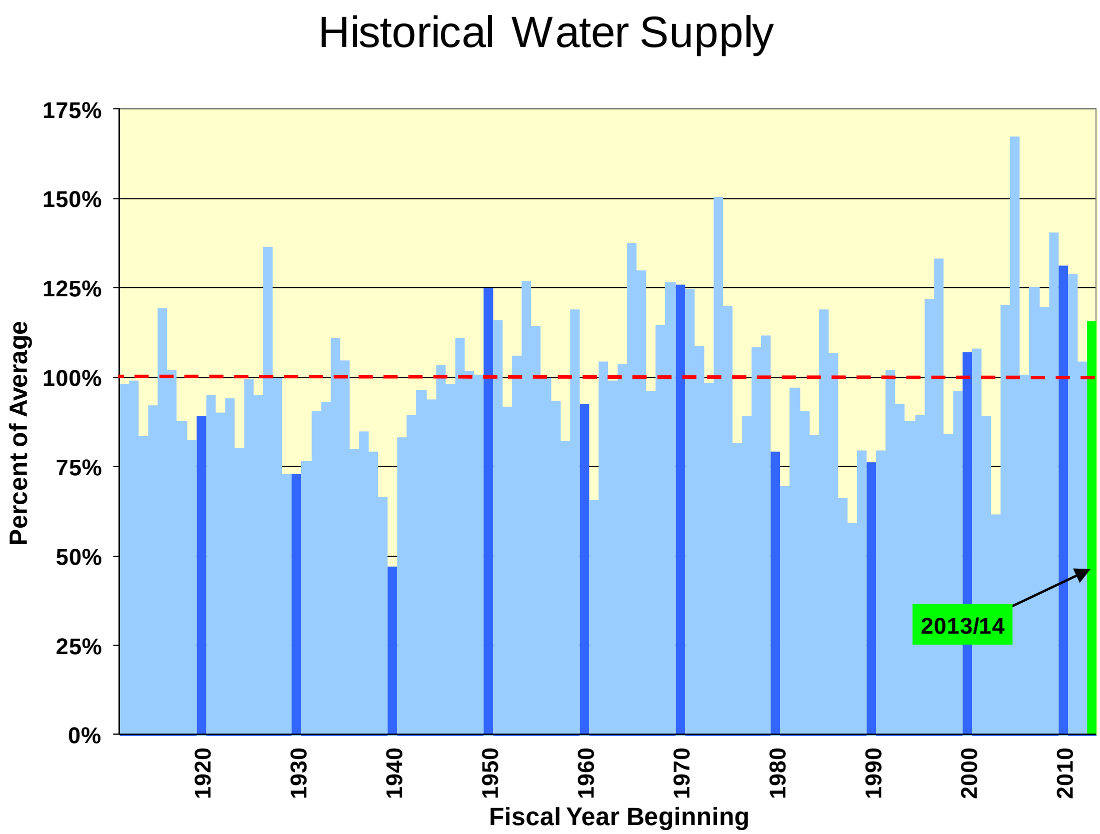
Precipitation

Overall precipitation across the Nelson-Churchill basin was near normal for the period April 1st, 2014 to November 30th, 2014. However, the timing of precipitation over this period was not uniform. Roughly two thirds of the total precipitation fell prior to the end of July, whereas the second half of this period was drier than normal. From August through November, precipitation was around 80% of average, or a 10th percentile event. In other words 90% of the time the system precipitation is higher than what was experienced in those four months of 2014. With low amounts of late-summer and fall precipitation resulting in below average soil moisture conditions, inflows from any snow melt runoff in the spring of 2015 are more likely to be below average.

Inflows

Annual total inflows (Figure 9.10) to the Manitoba Hydro system were well above average in 2013/14 extending the consecutive sequence of average or better water flows to ten years. Although 2014/15 is still underway, inflows for 2014/15 will be above average making this an eleven year sequence; the longest wet cycle on record. The previous record was five years. As indicated in Figure 9.10, the hydrologic record shows a history of long periods of above average conditions followed by similarly long periods of below average conditions and that the transition from one period to the other can occur quickly.

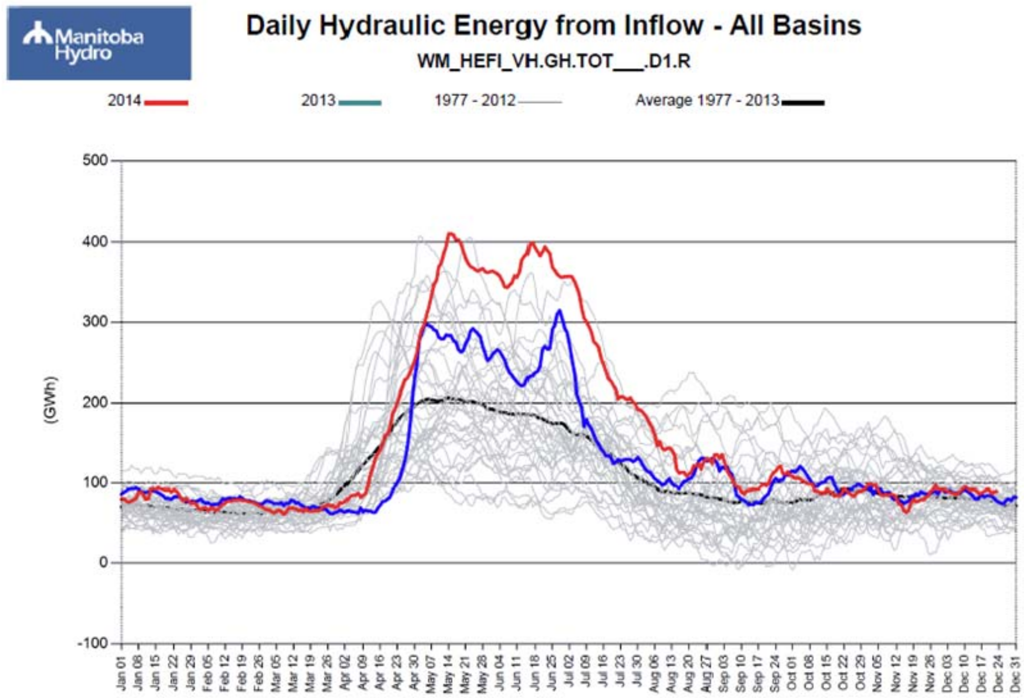
Figure 9.10 Historical Water Supply



The snowmelt runoff at the beginning of 2014/15 was delayed due to a late spring melt but flows transitioned quickly to well above average thereafter (Figure 9.11) reaching new record highs by mid-May as a result of heavy rainfall. High inflows were sustained through summer largely due to floods on the Assiniboine, Saskatchewan, and Winnipeg rivers. Flows on the Winnipeg River for the May through August period were the highest on record since 1977.

Annual system inflows for 2014/15 are projected to be among the top ten on record since 1912.

Figure 9.11 Daily Gross Hydraulic Energy from Inflow

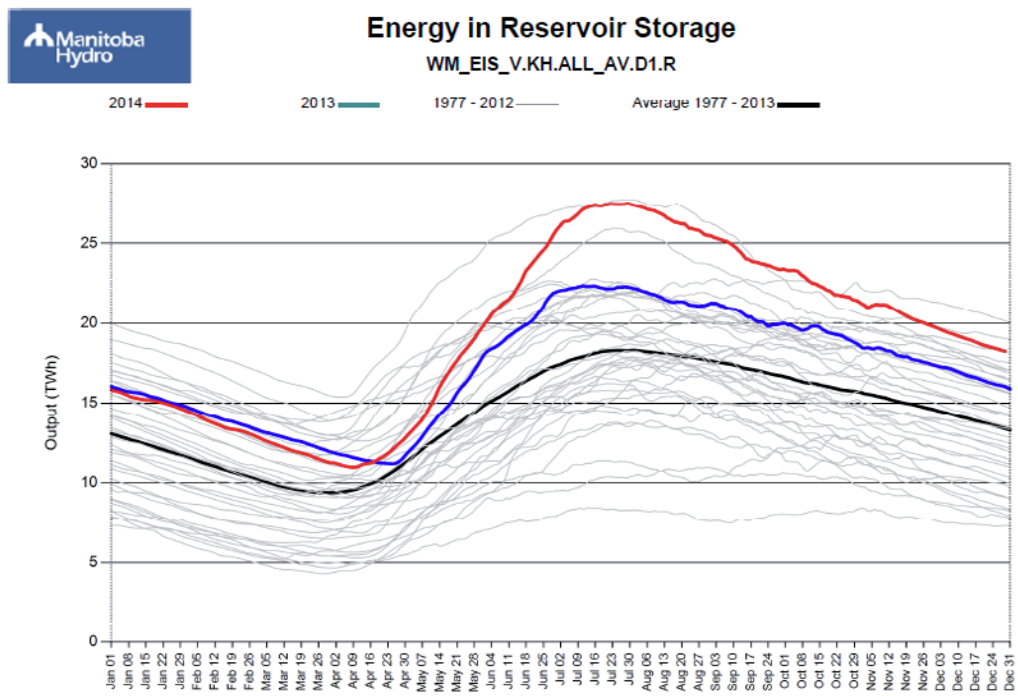


<u>Energy in Reservoir Storage</u>

Energy in reservoir storage is shown in Figure 9.12. This indicator is for the eighteen major reservoirs in Manitoba Hydro's watersheds including fourteen reservoirs regulated by other agencies.

As 2013/14 was an above average water year, reservoir storage was above average at the beginning of 2014/15. And with above average inflows through the first half of 2014/15 reservoir storage levels climbed steadily to near record high by July 2014. Manitoba Hydro expects energy in storage to be about 5 TWh above average at the beginning of 2015/16.

Figure 9.12 Total Energy in Reservoir Storage



Reservoir Operations

Reservoir operations in the first half of 2014/15 were centered around flood management due to the high inflows experienced on many tributaries to the system. New record flows were experienced on the Winnipeg River as a result of flooding conditions in the Rainy River and Lake of the Woods areas. Spill was required at Grand Rapids in order to manage flood inflows from the Saskatchewan River. Lake Winnipeg outflows were increased to maximum at the beginning of June, 2014 and this operation continued through to the end of October. Manitoba Hydro was required to spill water along the Nelson River from May into mid-November, 2014. In order to minimize flood levels along the lower reaches of the Nelson River, the Churchill River Diversion flow was minimized through the summer which required spillage down the Lower Churchill River from the Missi Falls Control Structure.

An extended outage of the 500 kV transmission line to the U.S. during October and early November restricted Manitoba Hydro’s ability to export electricity, which resulted in more spillage during this period.

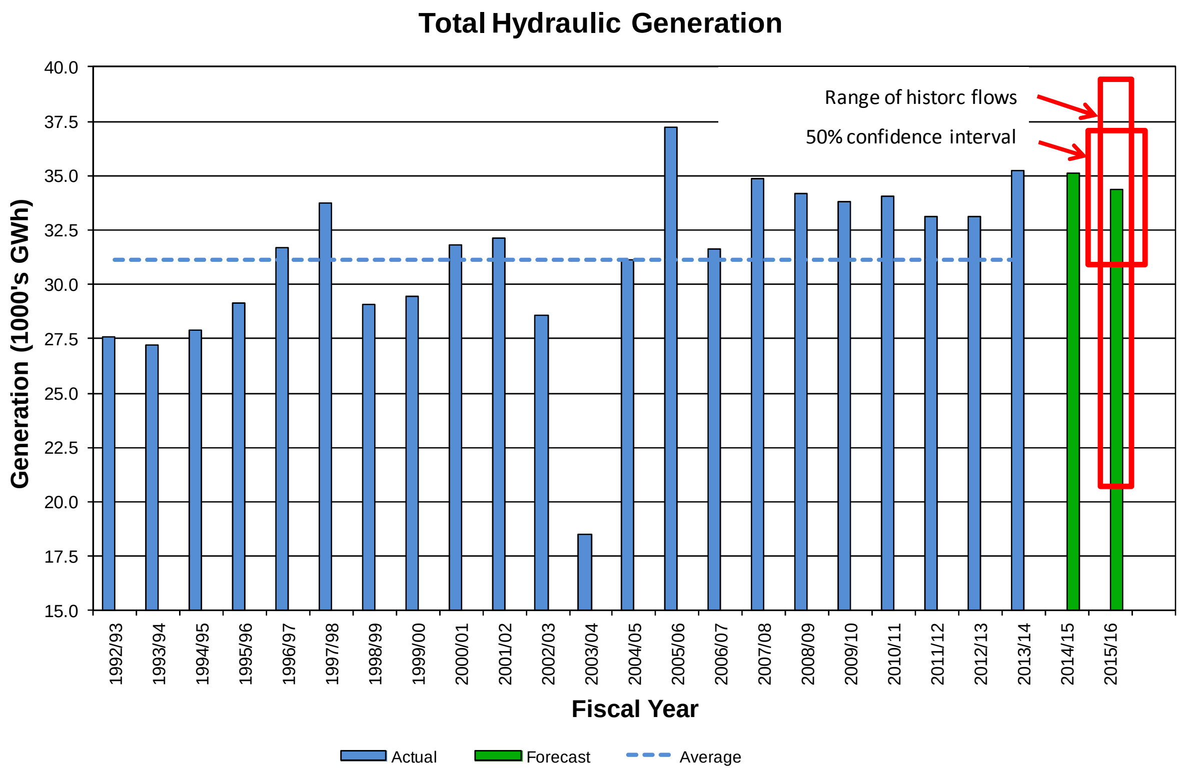
Given the favourable storage condition, Manitoba Hydro will continue to maximize Lake Winnipeg outflows and Churchill River Diversion flows through the winter in order to maximize Nelson River generation. However, as explained above, late summer and fall precipitation has been well below normal. The effect of below average fall antecedent precipitation is to lower spring snowmelt runoff. Manitoba Hydro will continue to monitor snowpack conditions through the winter months.

Total Hydraulic Generation

The forecast for 2015/16 assumes normal precipitation during the year. However, precipitation amounts can vary widely and as a result there is considerable uncertainty around the hydraulic generation forecast. Figure 9.13 shows the potential range assuming historic high and low flow years. In terms of the financial impact in 2015/16, the range of flow-related costs and revenues is $80M favourable with highest flows, and $380M unfavorable with lowest flows on record.

Total actual hydraulic generation since the in-service of Limestone Generating Station is shown in Figure 9.13 as well as the hydraulic generation forecast for 2014/15 and 2015/16.

Figure 9.13 Actual and Forecast Total Hydraulic Generation



9.7 FINANCIAL IMPACT OF DROUGHT

The reduction in hydroelectric energy supply during periods of extended low flow conditions can have a significant negative impact on Manitoba Hydro's financial situation. A repeat of a recent historic five-year drought (1987/88 to 1992/93) starting in 2016/17 would result in the lowest flow year of that historic drought occurring in 2017/18. In that lowest flow year (2017/18) net revenue would decrease by $0.5 billion compared to the net revenue based on the average of all flow conditions for that year. If the five-year historic drought (1987/88 to 1992/93) was repeated starting in 2016/17 and ending in 2020/21, net revenue would be about $1.5 billion less than expected over the five year period. This impact on net revenues would increase to $1.7 billion with consideration of financing costs associated with additional borrowing requirements up to the year 2020/21.

The estimate of $1.7 billion for the financial impact of a five-year drought is due to a significant reduction in export revenue combined with the requirement to operate high-cost Manitoba Hydro thermal generation facilities for long time periods and to import significant quantities of high-cost energy. There is a significant risk that this estimate could be greater if a series of adverse conditions occurred coincident with this time period. It is possible that natural gas prices, and consequently electricity prices in the export market, could be higher resulting not only in additional cost to operate Manitoba Hydro's gas-fired generation but also resulting in increased cost of import energy, especially during peak periods. Based on a high price scenario, the financial impact of a five-year drought would increase by $0.3 billion compared to the expected price scenario.

Another factor that has similar impacts as electricity prices in the export and import market is the currency exchange rate for the US dollar. A low Canadian dollar relative to the US dollar increases the export revenue that is lost in a drought and increases the cost of import energy and cost of operating thermal generation in Manitoba. This would be offset to some degree by reductions in finance expense denominated in USD.

A further factor that could increase the cost of drought is the occurrence of a more extreme drought compared to that which occurred during the five year period between 1987 and 1992. For example, a seven-year drought spanning from 2016/17 to 2022/23, based on flows from the period 1936/37 to 1942/43, increases the cost of drought from $1.5 billion to $2.1 billion under expected market prices.

Response to Directive 5 of Order 43/13

Table (a) - Hydraulic Generation

Month	Hydraulic Gross Generation (GWh)				
	Winnipeg River	Grand Rapids GS	Upper Nelson	Lower Nelson	Wuskwatim GS
Mar-2013	363	206	228	2109	133
Apr-2013	281	150	215	1906	130
May-2013	334	118	251	2056	141
Jun-2013	336	231	244	2022	115
Jul-2013	352	348	204	2199	111
Aug-2013	371	279	208	2302	109
Sep-2013	351	131	243	1893	86
Oct-2013	354	176	238	2177	139
Nov-2013	320	177	224	1984	139
Dec-2013	321	228	217	2148	136
Jan-2014	333	224	236	2016	133
Feb-2014	327	199	232	1769	116
Mar-2014	368	213	256	1981	133
Apr-2014	353	110	233	1959	110
May-2014	339	86	246	1891	146
Jun-2014	292	312	207	2026	111
Jul-2014	289	349	192	2250	94
Aug-2014	295	284	188	2356	80
Sep-2014	311	159	185	1997	74
Oct-2014	303	89	183	1586	101
Nov-2014	283	213	251	2073	123
Dec-2014	322	205	238	2268	137
Jan-2015	335	218	237	2299	136
Feb-2015	322	198	212	1953	120
Mar-2015	349	112	236	2146	142

Chart (b) - Energy in Storage

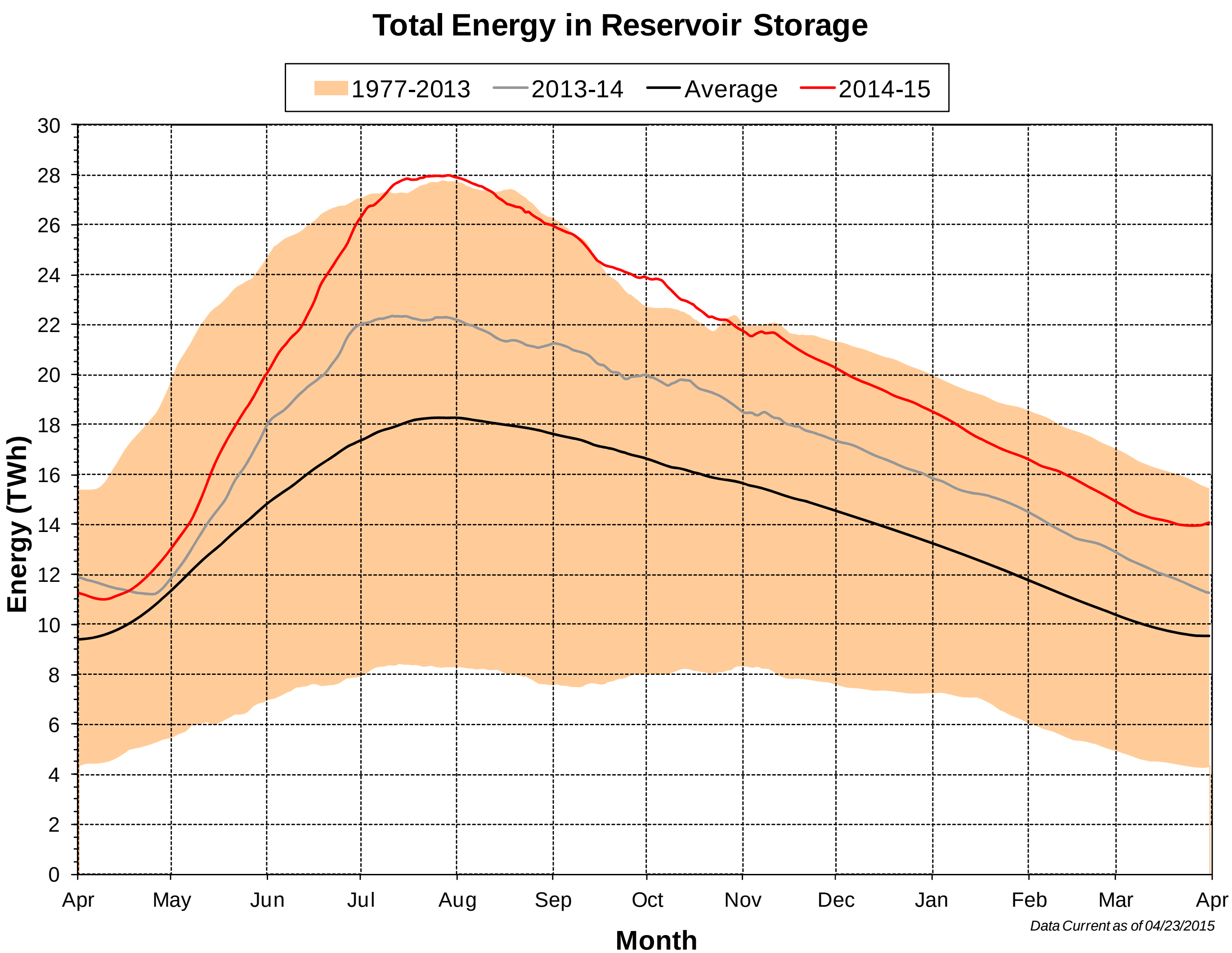


Table (b) - Monthly Average Lake Winnipeg Water Level

Month	Lake Winnipeg (m)
Mar-2013	217.42
Apr-2013	217.38
May-2013	217.49
Jun-2013	217.73
Jul-2013	217.93
Aug-2013	217.85
Sep-2013	217.75
Oct-2013	217.67
Nov-2013	217.59
Dec-2013	217.54
Jan-2014	217.50
Feb-2014	217.51
Mar-2014	217.51
Apr-2014	217.52
May-2014	217.71
Jun-2014	217.98
Jul-2014	218.28
Aug-2014	218.34
Sep-2014	218.23
Oct-2014	218.02
Nov-2014	217.87
Dec-2014	217.79
Jan-2015	217.72
Feb-2015	217.70
Mar-2015	217.66

Table (c) - Monthly Average Flow Data

Month	Monthly Average Flow (cms)					
	Winnipeg River at Great Falls GS	Red River at Lockport	Sask. River at Grand Rapids GS	Nelson River at Kelsey GS	Burntwood River Near Thompson	Nelson River at Kettle Gs
Mar-2013	951	90	867	2559	1004	3795
Apr-2013	707	302	645	2382	1006	3538
May-2013	954	1525	490	2427	1065	3639
Jun-2013	1816	962	1000	2481	933	3718
Jul-2013	1688	632	1807	3670	774	4464
Aug-2013	1107	281	1285	3822	730	4863
Sep-2013	1007	153	555	2809	941	3907
Oct-2013	1045	163	720	2599	1154	3943
Nov-2013	860	109	742	2606	1078	3856
Dec-2013	820	96	948	2704	1131	3810
Jan-2014	839	75	947	2563	1034	3632
Feb-2014	988	57	962	2433	1019	3542
Mar-2014	1000	79	948	2403	1011	3568
Apr-2014	1003	756	495	2347	966	3622
May-2014	1937	1037	369	2786	1251	4120
Jun-2014	2598	960	1375	3819	882	5027
Jul-2014	2763	1115	1786	4621	687	5579
Aug-2014	2305	524	1225	4992	575	5759
Sep-2014	1688	493	698	4877	532	5628
Oct-2014	771	274	374	4533	618	5411
Nov-2014	698	151	911	2980	860	4239
Dec-2014	781	112	855	3070	1081	4080
Jan-2015	843	96	919	2972	1007	4119
Feb-2015	917	102	943	2804	1004	3883
Mar-2015	907	180	486	2658	1071	3874

Table (d.1) - Sales and Purchases Filed with NEB

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Mar-13	35	86,700	2,820,083	3.3						
	224	168,000	9,789,201	5.8						
	345	771	55,660	7.2						
	355				352,598	11,406,112	3.2			
								10,005	374,131	3.7
Apr-13	35	103,820	3,357,126	3.2						
	224	171,343	9,831,099	5.7						
	345	672	47,102	7.0						
	355				354,939	11,822,526	3.3			
								17,123	495,957	2.9
May-13	35	111,440	3,163,407	2.8						
	224	183,788	10,749,558	5.8						
	345	341	27,081	7.9						
	355				464,857	13,582,975	2.9			
								2,505	87,170	3.5

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jun-13	33	32,938	1,322,307	4.0						
	34	24,702	991,670	4.0						
	35	107,636	2,945,708	2.7						
	224	158,794	9,953,623	6.3						
	345	414	31,011	7.5						
	352	9	1,175	13.1						
	355				852,421	20,994,789	2.5			
								1,686	91,559	5.4
Jul-13	33	60,366	2,371,542	3.9						
	34	45,275	1,778,676	3.9						
	35	111,334	3,463,052	3.1						
	224	183,917	10,700,422	5.8						
	345	434	32,283	7.4						
	355				955,531	25,629,741	2.7			
								2,474	186,819	7.6
Aug-13	33	54,620	2,201,290	4.0						
	34	41,003	1,652,499	4.0						
	35	111,495	3,339,358	3.0						
	224	174,750	10,617,822	6.1						
	345	376	28,247	7.5						
	379	80,023	2,216,928	2.8						
	355				902,359	22,540,778	2.5			
								2,469	433,454	17.6

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Sep-13	33	20,789	816,559	3.9						
	34	15,585	612,154	3.9						
	35	80,035	2,134,183	2.7						
	224	130,146	8,644,370	6.6						
	345	376	30,511	8.1						
	379	57,526	1,435,549	2.5						
	355				651,033	15,711,517	2.4			
								2,679	104,702	3.9
Oct-13	35	106,105	3,045,103	2.9						
	224	183,718	10,840,420	5.9						
	345	415	32,481	7.8						
	379	53,097	1,701,338	3.2						
	355				752,750	19,523,112	2.6			
								738	24,482	3.3
Nov-13	35	83,290	2,287,598	2.7						
	224	153,190	9,815,402	6.4						
	345	696	49,473	7.1						
	379	25,132	796,919	3.2						
	355				310,592	8,792,251	2.8			
								21,725	539,951	2.5

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Dec-13	35	52,414	2,191,693	4.2						
	224	136,243	9,517,567	7.0						
	345	893	64,070	7.2						
	352	16	1,926	12.0						
	355				89,619	4,554,245	5.1			
								73,075	2,707,912	3.7
Jan-14	35	20,400	883,602	4.3						
	224	179,829	11,397,041	6.3						
	345	1,339	88,923	6.6						
	355				90,736	7,153,983	7.9			
								176,865	8,488,522	4.8
Feb-14	35	4,500	250,082	5.6						
	224	158,243	10,464,053	6.6						
	355				105,955	7,341,754	6.9			
								143,638	6,065,761	4.2
Mar-14	35	44,100	1,594,046	3.6						
	224	166,631	10,791,002	6.5						
	355				269,824	11,669,319	4.3			
								70,686	2,883,423	4.1

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Apr-14	35	93,413	2,858,196	30.60						
	224	171,075	10,874,752	63.57						
	345	646	50,353	77.95						
	355				425,204	13,256,983	31.18			
								15,591	704,819	45.21
May-14	35	62,597	2,133,036	34.08						
	224	153,376	10,113,960	65.94						
	345	492	36,654	74.50						
	355				500,883	14,512,390	28.97			
	379	56,897	1,596,704	28.06						
								1,039	96,058	92.45
Jun-14	33	34,004	1,392,207	40.94						
	34	25,503	1,044,156	40.94						
	35	104,869	3,049,172	29.08						
	224	166,910	10,475,140	62.76						
	345	393	31,252	79.52						
	352	15	1,789	119.27						
	355				744,637	18,443,973	24.77			
	379	74,512	1,889,520	25.36						
								1,724	157,335	91.26

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jul-14	33	54,236	2,265,066	41.76						
	34	40,693	1,699,468	41.76						
	35	109,930	3,097,594	28.18						
	224	177,986	11,135,017	62.56						
	345	411	32,095	78.09						
	355				805,822	20,458,853	25.39			
	379	76,895	2,050,328	26.66						
								2,682	99,522	37.11
Aug-14	33	53,572	2,230,761	41.64						
	34	40,179	1,673,071	41.64						
	35	111,535	3,459,257	31.01						
	224	167,840	10,691,381	63.70						
	345	446	33,090	74.19						
	355				842,745	23,057,388	27.36			
	379	77,556	2,244,478	28.94						
								4,954	294,238	59.39

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Sep-14	33	28,101	1,207,856	42.98						
	34	21,070	905,645	42.98						
	35	101,590	2,599,528	25.59						
	224	162,724	10,822,131	66.51						
	345	362	29,507	81.51						
	355				574,335	12,918,717	22.49			
	379	69,976	1,550,750	22.16						
								1,302	54,496	41.86
Oct-14	35	39,011	937,722	24.04						
	224	135,671	9,749,090	71.86						
	345									
	355				159,474	4,219,443	26.46			
	393	453	31,108	68.67						
								426	8,820	20.70
Nov-14	224	159,835	10,910,455	68.26						
	355				386,148	12,020,955	31.13			
	393	683	51,383	75.23						
								61,354	1,580,745	25.76
Dec-14	224	183,763	12,111,995	65.91						
	352	19	2,262	119.05						
	355				323,437	10,594,264	32.76			
	393	828	61,108	73.80						
								29,342	1,174,253	40.02

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Jan-15	224	175,885	12,903,464	73.36						
	355				289,419	9,613,588	33.22			
	393	1,189	83,640	70.34						
								29,126	1,296,907	44.53
Feb-15	224	160,000	11,950,287	74.69						
	355				90,826	4,544,442	50.03			
	393	1,170	82,455	70.47						
								27,569	1,369,012	49.66
Mar-15	224	176,000	12,874,405	73.15						
	355				428,471	12,567,406	29.33			
	393	569	31,345	55.09						
								9,645	147,488	15.29

Table (d.2) - MISO Sales

Month	MWh	$Cdn	Avg Price $/MWh
Mar-2013	276,273	8,178,435	29.47
Apr-2013	254,607	7,758,784	30.54
May-2013	669,266	17,046,682	25.29
Jun-2013	770,944	17,736,990	23.29
Jul-2013	797,967	20,086,498	25.15
Aug-2013	814,051	19,022,798	23.49
Sep-2013	618,380	14,371,211	23.41
Oct-2013	722,130	17,438,224	24.14
Nov-2013	272,745	7,334,825	26.70
Dec-2013	6,632	47,628	18.22
Jan-2014	56,914	4,613,696	81.00
Feb-2014	78,129	5,286,446	67.72
Mar-2014	236,307	9,705,090	40.98
Apr-2014	339,060	9,713,490	29.28
May-2014	421,960	11,310,150	27.33
Jun-2014	627,300	14,133,170	22.55
Jul-2014	711,240	18,000,760	23.91
Aug-2014	739,770	18,995,370	25.81
Sep-2014	465,710	9,082,600	19.78
Oct-2014	106,030	2,370,000	22.25
Nov-2014	334,560	9,421,180	28.58
Dec-2014	282,370	8,322,730	29.56
Jan-2015	238,190	6,907,270	28.98
Feb-2015	63,571	2,542,145	41.13
Mar-2015	384,931	10,219,384	26.56

Notes:

1. MISO Sales include Real Time and Day Ahead transactions.

Table (d.3) - Canadian Extraprovincial Sales

Month	MWh	$Cdn	Avg Price $/MWh
Mar-2013	67,863	2,907,552	42.96
Apr-2013	56,602	2,346,493	36.45
May-2013	35,423	1,149,651	30.33
Jun-2013	21,617	929,329	25.24
Jul-2013	29,760	916,771	23.47
Aug-2013	100,600	3,298,657	31.88
Sep-2013	76,481	2,904,089	36.34
Oct-2013	75,112	2,672,767	33.90
Nov-2013	82,006	2,367,753	27.47
Dec-2013	48,233	2,365,698	46.65
Jan-2014	49,446	2,255,749	47.12
Feb-2014	70,476	4,579,106	62.51
Mar-2014	75,675	6,127,424	60.93
Apr-2014	64,429	1,596,480	37.91
May-2014	102,883	2,799,689	29.26
Jun-2014	76,017	2,668,379	34.86
Jul-2014	79,574	2,860,807	29.39
Aug-2014	60,353	2,084,675	32.27
Sep-2014	60,757	1,901,391	29.43
Oct-2014	95,151	3,385,659	35.34
Nov-2014	92,426	3,846,595	39.89
Dec-2014	87,114	3,853,628	44.23
Jan-2015	77,080	4,231,771	53.00
Feb-2015	72,198	4,456,383	57.72
Mar-2015	101,640	4,575,239	44.06

Table (d.4) - Purchases

Month	MWh	$Cdn	Avg Price $/MWh
Mar-2013	101,192	5,835,134	57.66
Apr-2013	128,406	7,124,768	55.49
May-2013	107,766	6,672,022	61.91
Jun-2013	90,514	4,930,776	54.48
Jul-2013	76,503	4,186,686	54.73
Aug-2013	61,884	3,628,264	58.63
Sep-2013	125,554	5,892,456	46.93
Oct-2013	129,232	6,182,279	47.84
Nov-2013	162,980	8,344,787	51.20
Dec-2013	189,212	9,602,634	50.75
Jan-2014	263,076	14,407,724	54.77
Feb-2014	168,515	10,260,545	60.89
Mar-2014	129,195	7,682,567	59.46
Apr-2014	104,281	6,632,811	63.61
May-2014	81,739	5,621,824	68.78
Jun-2014	75,342	5,295,447	70.29
Jul-2014	73,834	4,797,289	64.97
Aug-2014	42,244	3,355,066	79.42
Sep-2014	77,162	5,774,454	74.84
Oct-2014	109,601	7,990,897	72.91
Nov-2014	160,472	8,917,349	55.57
Dec-2014	103,450	6,610,948	63.90
Jan-2015	125,578	8,291,282	66.02
Feb-2015	116,558	7,454,091	63.95
Mar-2015	108,691	7,077,797	65.12

Notes:

1. Includes Day Ahead and Real Time Purchases and wind generation purchases.

2. Aggregated information is provided to comply with confidentiality provisions of power purchase agreements.

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

PUB DIRECTIVES AND INTERIM ORDERS

INDEX

MANITOBA HYDRO
2015/16 & 2016/17 GENERAL RATE APPLICATION

PUB DIRECTIVES AND INTERIM ORDERS

10.0 OVERVIEW

Tab 10 outlines the interim Orders for which Manitoba Hydro is seeking final PUB approval in Section 10.1 and provides responses to and status of PUB directives in Sections 10.2 to 10.4.

10.1 FINAL APPROVAL OF INTERIM ORDERS

Manitoba Hydro is seeking final approval of interim and *ex parte* Orders as follows:

a) Final approval of Orders 49/14 and 51/14 which approved, on an interim basis, a 2.75% rate increase effective May 1, 2014 applied on an across-the-board basis, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to conclusion of this proceeding;

b) Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class approved on an interim basis in Order 79/14;

c) Final approval of all SEP interim *ex parte* rate Orders, as outlined in Appendix 10.1, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

d) Final approval of CRP *ex parte* Order 46/14 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of this Application and prior to the PUB's Order in this matter; and,

e) Final approval of interim Orders, as outlined in Appendix 10.1, related to the four remote communities served by diesel generation, as outlined in Manitoba Hydro's Application.

Appendix 10.1 includes a complete list of interim and *ex parte* Orders up to January 2015 which require final approval.

10.2 DIRECTIVES FROM ORDER 43/13

10.2.1 Interim Application Filing Requirements

5. That Manitoba Hydro file with the Board, as part of any future interim application for rate increases, the following information on a monthly basis for the previous three months, and on an on-going basis until a rate Order in respect of the Application is issued:

(a) Hydraulic generation monthly data (GWh) for the Winnipeg River System, Grand Rapids, Upper Nelson River Generating Station(s), Lower Nelson River Generating Station(s), and Wuskwatim Generating Station;
(b) Monthly adjusted system energy-in-storage curves and Lake Winnipeg water levels;
(c) Average monthly flow data for the Winnipeg River, Saskatchewan River, and Upper Nelson River (Kelsey Generating Station) and Lower Nelson River (Kettle Generating Station);
(d) Monthly extra-provincial energy exchange data (volumes and prices) for National Energy Board-filed sales and purchases (by permit / license number), Midwest Independent System Operator day-ahead and real-time sales and purchases, and Canadian sales and purchases; and
(e) Monthly updates to Manitoba Hydro's financial results relative to its forecast.

Status: Ongoing
Manitoba Hydro has provided the information from (a) to (d) for the period April to December 2014 as Appendix 9.1 of this Application. Manitoba Hydro will provide this information on an ongoing basis until a rate Order in respect of the April 1, 2015 interim rate request is issued by the PUB.

With respect to item (e) above, Manitoba Hydro has provided the Manitoba Hydro-Electric Board ("MHEB") quarterly report for the six months ended September 30, 2014 as Appendix 5.3 of this Application. Manitoba Hydro will file with the PUB, the MHEB quarterly report for the nine months ended December 31, 2014 once it is publicly released, which is expected to be in late February 2015.

10.2.2 IFRS Status Update Report

6. That Manitoba Hydro file with the Board an International Financial Reporting Standards status update report prior to the next General Rate Application that will provide the Board options available for rate-setting purposes.

Status: Complete
Manitoba Hydro has provided its International Financial Reporting Standards ("IFRS") status update report as Appendix 3.4 of this Application.

As outlined in Appendix 5.7 of Tab 5, the overall impacts of the accounting policy and estimate changes that are forecast to be made in 2014/15 and 2015/16 offset each other and result in an overall reduction in Manitoba Hydro's future revenue requirements, and as such are not driving the need for the proposed rate increases.

Given that the net impact of these changes are not driving the need for rate increases, it is the position of Manitoba Hydro that IFRS financial reporting policies should be adopted for rate-setting purposes as they are in no way harming ratepayers. Furthermore, as has been the position of Manitoba Hydro as previous rate proceedings, under the cost of service rate-making approach that has been utilized by Manitoba Hydro, it is unnecessary and undesirable to maintain two sets of financial records, one for financial reporting purposes and one for rate-setting purposes. To do so, would cause confusion between Manitoba Hydro and its various stakeholders, including the PUB as they would be using different sets of financial information to make important decisions with respect to the Corporation's operations and finances.

10.2.3 Asset Condition Assessment Report

7. That Manitoba Hydro complete and file with the Board an Asset Condition Assessment Study no later than the filing of the next updated depreciation study with the Board.

Status: Complete
Manitoba Hydro has provided its electric infrastructure condition assessment report as Appendix 4.2 of this Application.

10.2.4 Comparison of ELG vs. ASL under IFRS

8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.

9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

Status: Open

Manitoba Hydro has previously advised the PUB that it is not able to provide a comparison of ELG and ASL IFRS compliant depreciation rates based on a full ASL depreciation study. As such, Manitoba Hydro has been working on an alternate approach that does not require a full ASL depreciation study, but would demonstrate the impacts of using ELG versus ASL methodologies. Manitoba Hydro anticipates filing a response with respect to these Directives before receipt of Round 1 Information Requests in the current proceeding.

10.2.5 Adequacy of Manitoba Hydro's Financial Reserves

10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board.

Status: Open

Manitoba Hydro has recently commenced a review of its financial targets and KPMG has been selected as the consultant to provide recommendations to Manitoba Hydro on the appropriate financial targets which align with the mandate of the Corporation and the interests of its stakeholders considering its operating and business outlook and associated risks. The review will consider the objectives of maintaining rate stability for customers and Manitoba Hydro's self-supporting status for credit rating purposes. It is expected that this review will completed in time for the approval of IFF15 by the MHEB in late fall of 2015.

As part of this review, analysis will also be provided to satisfy PUB Directive 10 from Order 43/13 to review Manitoba Hydro's operating and financial risks in order to assess the adequacy of financial reserves, including, as appropriate, the use of quantitative and probabilistic analysis. It is expected that this information would be available for review by the PUB at the next GRA proceeding.

Manitoba Hydro has filed extensive information in Appendices 3.5 and 3.6 of the Application with respect to the financial impacts of the key risks of the Corporation, as well as the financial implications of various alternative rate scenarios. Manitoba Hydro is of the view that this information provides adequate support for the PUB to approve Manitoba Hydro's Application for 2015/16 and 2016/17.

10.2.6 WPLP Agreement Changes

11. That Manitoba Hydro file with the Board any negotiated agreements or changes with respect to the Wuskwatim Power Limited Partnership when finalized, and detail the impacts on Manitoba Hydro's operating results and rates.

Status: Open
Manitoba Hydro and Nisichawayasihk Cree Nation ("NCN") have reached an agreement-in-principle on a majority of terms within the Wuskwatim Project Development Agreement ("PDA"). The parties are still in the process of conducting a review and negotiating final terms of the PDA. As part of NCN's approval process, NCN will be required to conduct community consultations prior to ratifying any final agreement. If an agreement is finalized prior to the end of the GRA, Manitoba Hydro will provide a copy of the executed agreement to the PUB.

As noted in IFF14 at page 13, the projected net impact to Manitoba Hydro of the terms of the Agreement in Principle averages approximately $15 million per year over the 20-year forecast period.

10.2.7 <u>DSM Deferral Account</u>

12. That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application.

Status: Open

Pursuant to Order 43/13, Manitoba Hydro established a rate-regulated liability and a corresponding rate-regulated asset in the amount of $16 million for Electric operations in its financial statements for the year ended March 31, 2014. The PUB confirmed that this accounting treatment is consistent with the intent of Order 43/13 and noted that Manitoba Hydro has increased planned DSM spending in its 2014 Power Smart Plan and indicated that it will assess the status of the rate-regulated asset and liability at the next GRA.

Manitoba Hydro's understanding is that the intent of establishing the DSM deferral account was to encourage the Corporation to increase its level of DSM programming. If its understanding is correct, then Manitoba Hydro is of the view that the intent of this Directive has now been satisfied by the higher level of DSM spending set forth in the 2014 Power Smart Plan. Accordingly, Manitoba Hydro is requesting the PUB's approval to rescind the Demand Side Management deferral account established pursuant to Order 43/13 for the 2012/13 and 2013/14 fiscal years and on a go-forward basis.

10.2.8 <u>Curtailable Rate Program Changes</u>

13. That Manitoba Hydro's proposed changes to the Curtailable Rate Program BE AND ARE HEREBY APPROVED ON AN INTERIM BASIS, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.

Status: Open

By letter of May 15, 2013, Manitoba Hydro advised the PUB that two of the proposed changes to the Curtailable Rate Program (“CRP”) are difficult to implement on an interim basis as customer decisions in response to these changes are not easily reversible if these changes are not subsequently approved as final. As such, Manitoba Hydro requested to defer implementation of the change in the defined hours for peak and off-peak periods, and the elimination of Curtailment Options “C” and “CE”, until such time as the PUB grants final approval. By letter of June 25, 2013, the PUB confirmed Manitoba Hydro’s request to defer implementation of these changes.

Manitoba Hydro is seeking confirmation that the PUB accepts the rate approval process given the proposed modifications to the CRP that were approved on an interim basis in Order 43/13, as outlined in Tab 6 of this Application. Manitoba Hydro will implement these changes upon final approval from the PUB.

10.2.9 Surplus Energy Program Changes

15. That Manitoba Hydro’s Option 1 Surplus Energy Program rate offering BE AND IS HEREBY APPROVED ON AN INTERIM BASIS, to be reviewed by the Board at a Cost of Service/Time of Use hearing.

Status: Open

Manitoba Hydro is seeking confirmation that the PUB accepts the rate approval process given proposed modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program that were approved on an interim basis in Order 43/13, as outlined in Tab 6 of this Application.

10.3 DIRECTIVES FROM ORDER 134/10

10.3.1 Confirmation of Diesel Settlement Agreement and Interim Rates

3. MH file with the Board and all Parties to this Diesel Zone Application:

(a) Confirmation that the Settlement Agreement (from the 2004 Minutes of Settlement) has been fully executed;

(b) A true copy of the fully executed Settlement Agreement;

(c) Confirmation of payments or adequate funding arrangements for the capital costs incurred by MH, by community, since 2004; and
Indication of capital costs still in dispute, if any, and the process and timeline for resolution of such dispute(s).

4. MH, supported by the written consents of INAC, MKO, the four First Nations and CAC/MSOS, is to seek an Order of this Board to confirm, as final, all Diesel Zone rates approved on an interim basis since 2004, including those interim rate approvals in Board Orders 17/04, 46/04, 159/04, and 176/06.

Status: Open
Manitoba Hydro has previously advised the PUB that on January 24, 2011 Manitoba Hydro received an email from Manitoba Keewatinowi Okimakinak ("MKO") attaching PDF copies of the Settlement Agreement and related authorizing documents. On February 28, 2011 Manitoba Hydro provided to the PUB, PDF copies of the Settlement Agreement as forwarded by MKO. To date, Manitoba Hydro has not received true copies of the Settlement Agreement and related documents.

On June 16, 2011, MKO advised Manitoba Hydro and Aboriginal Affairs and Northern Development Canada ("AANDC") that MKO had received most of the originals. Missing were three original Band Council Resolutions and one original Certificate of Independent Legal Advice. Manitoba Hydro was advised by MKO that these documents could not be located by either MKO or the First Nations.

To remedy this situation, AANDC proposed that for each of the four documents, a sworn declaration by one of the signatories to the document attesting that either the fax copy or the PDF (depending upon the circumstances) is a true copy of the original document and that the document was signed on that particular date. Manitoba Hydro and MKO concurred with the proposed remedy and action was to be taken by MKO in this regard.

On October 28, 2011, Manitoba Hydro received from MKO, PDF copies of three of the four sworn declarations. Specifically, Manitoba Hydro received PDF copies of the sworn declarations from representatives of MKO, Tadoule Lake and Barren Lands. Manitoba Hydro has not been advised by MKO as to whether it has yet secured a sworn declaration from Shamattawa.

During the 2012/13 & 2013/14 GRA, Manitoba Hydro informed the PUB that AANDC advised that a compensation issue had arisen between AANDC and MKO, which did not involve Manitoba Hydro. Manitoba Hydro is not privy to the exact details but was advised that the issue is related to the Settlement Agreement. AANDC has indicated that as of December 2014, there has been no change in circumstances and MKO has not yet provided the true copies of the Settlement Agreement.

As to capital costs listed in items c) and d) Manitoba Hydro can confirm that two payments have been received from AANDC: on March 31, 2011 it received a cheque from AANDC in the amount of $2,296,447, and on April 4, 2012 a cheque in the amount of $5,763,738 for a total payment to date of $8,060,185. On April 4, 2013 a cheque was received from AANDC in the amount of $1,753,477.00. This represents the majority of outstanding capital items since March 31, 2004 except for soil remediation for which contribution was due from AANDC.

With respect to the consents described in Directive 4 above, in December of 2011, Manitoba Hydro forwarded consents to AANDC, MKO and CAC as requested by the PUB. AANDC has not provided an executed copy of the consent, CAC has indicated that prior to providing its consent, it would require a final copy of the Settlement Agreement. MKO has not provided its position. It is Manitoba Hydro's position that the PUB does not require any third parties consent to exercise its jurisdiction and that there is no further process required in order to finalize the interim orders, subject to receipt of the true copies of the Settlement Agreement.

Until Manitoba Hydro and AANDC are in the possession of the true copies of the Settlement Agreement, there exists a remote possibility that the agreement could be unwound which includes return of significant capital contributions paid. In this event, Manitoba Hydro would not want rates designed on the basis that capital contributions have been received, to have already been finalized.

Manitoba Hydro's application requests that the PUB give final approval to all outstanding interim order provided that true copies of the Settlement Agreement have been filed. If the Settlement Agreement has not been filed prior to the PUB issuing its order following review of the current rate application, Manitoba Hydro would request that finalization of the diesel rates be deferred.

10.4 DIRECTIVES FROM ORDER 150/08

10.4.1 Independent Benchmarking Study

6. MH to undertake and file with the Board, by a date to be fixed by the Board after its review of the study outline to be filed by MH by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:

(a) Primary key drivers of OM&A in each operational division [Board preference is for a divisional break-down to allow for a comparison with other utilities, even if the comparison needs to be limited to specific divisions/activities],
(b) Comparable other Canadian Utility data for each of the drivers;
(c) Key comparison indicators, including staffing levels;
(d) A comparison with and discussion of industry best practices; and
(e) Potential improvement areas.

The Board expects to be apprised of the scope of the benchmarking study in advance of it being undertaken, and will anticipate being provided a study outline on or before June 30, 2009, to allow the Board the opportunity to provide direction and/or comment.

Status: Deferred.
In April 2010, Manitoba Hydro requested this directive to be deferred. In Order 5/12, the PUB acknowledged that Manitoba Hydro has deferred this Directive until after the implementation of IFRS.

Prior uncertainty surrounding the treatment of rate-regulated assets and liabilities under IFRS has resulted in divergence in practice with respect to the financial reporting frameworks (IFRS, US GAAP) used by Canadian electric utilities which could seriously complicate a benchmarking exercise.

Moreover, benchmarking among utilities with respect to cost performance has always been problematic due to differences in resource endowment, distribution of customers, customer density, market environment, policy environment and other variables.

Manitoba Hydro is concerned that detailed benchmarking of operating costs could be a costly exercise, likely to yield inconclusive results at best.

Manitoba Hydro has a series of corporate measures and targets which it uses to assess the performance of the Corporation and its progress towards attainment of its key objectives. These measures and targets as well as actual results are included in the corporate performance dashboard, which is provided in the following figure for the year ending March 31, 2014. As outlined in Tab 3, Manitoba Hydro has three primary financial targets that are used to assess the financial strength of the Corporation.

In addition, Manitoba Hydro also prepares an annual survey of Canadian electricity bills to compare bills paid by Manitoba customers with those of other major Canadian utilities'. The current Survey of Canadian Electricity Bills reflecting rates in effect as of May 1, 2014 is provided as Appendix 6.14 to Tab 6.

Figure 10.1

Corporate Performance Dashboard (Q4 results as at March 31, 2014)

	Measure	Target	Result
Safety in the Workplace *Q4 results, ending March 31, 2014*	Accident severity rate	<12 days per 200,000 hours worked	11.07
	Accident frequency rate	<.60 accidents per 200,000 hours worked	0.69
	High risk incidents	0 incidents	0
Customer Value *Q4 results, ending March 31, 2014*	System Average Interruption Duration (SAIDI)	< 116 minutes	106.5 minutes
	System Average Interruption Frequency (SAIFI)	<1.4 per year	1.26 outages
	Customer satisfaction (CSTS - Manitoba Hydro quarterly survey)	>8.4/10 customer satisfaction with overall service	7.87
Aboriginal Relations *Q4 results, ending March 31, 2014*	Aboriginal employment	16% overall	17.6%
Protecting the Environment *Q4 results, ending March 31, 2014*	Progress towards environmental targets*	Achieve all 3 targets	3 of 3
Demand Side Management (DSM) *Q4 results, ending March 31, 2014*	Electric energy saved	174 GWh	308 GWh
	Electric capacity saved	201 MW	278 MW
	Natural gas energy saved	10 million cubic meters	8.5 million cubic meters

	Measure	Annual Budget	YTD Budget	YTD Actual	Variance / %
Financial Strength (per IFF13) for the 12-month period ending March 31, 2014	Net income (Loss) ($ thousands)	135,846	135,846	174,272	28%
	OM&A costs (consolidated) ($ thousands)	556,401	556,401	556,862	0%
	Capital expenditures - electric operations - ***Major New Generation & Transmission*** ($ thousands)	1,071,058	1,071,058	983,713	-8%
	Capital expenditures - electric & gas operations - ***Major & Base Capital*** ($ thousands)	575,550	575,550	510,850	-11%

Notes:

* Environmental sub-targets:	a-Percentage of electricity generated in Manitoba from renewable resources	Target: ≥ 99%
	b-Total annual GHG emissions	Target: ≤ 520 kt
	c-Repeat environmental audit findings	Target: 0 repeat findings

PUB *Ex Parte* Orders		
Order No.	**Date**	**Curtailable Rates Program**
43/13	April 26, 2013	Approval of Terms and Conditions
46/14	April 28, 2014	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2014

PUB *Ex Parte* Orders		
Order No.	**Date**	**General Consumer Rates**
49/14	May 6, 2014	Approval for a General Rate Increase May 1, 2014
51/14	May 7, 2014	Approval of May 1, 2014 Rate Schedules flowing from BO 49/14
79/14	July 15, 2014	Approval for New Light Emitting Diode (LED) rates for Area and Roadway Lighting Class Effective August 1, 2014

PUB *Ex Parte* Orders		
Order No.	**Date**	**Remote Communities Served by Diesel Generation**
17/04	February 6, 2004	Increase in Electric Rates in Remote Communities Served by Diesel Generation
46/04	March 25, 2004	Increases in Electric Rates in Remote Communities Served by Diesel Generation resulting from Board Order 17/04
159/04	December 22, 2004	New Electricity Rates in Remote Communities Served by Diesel Generation
176/06	December 21, 2006	New Electricity Rates in Remote Communities Served by Diesel Generation
1/10	January 5, 2010	Review of Issues Related to Current Electricity Rates Charged in Remote Communities Served by Diesel Generation
134/10	December 22, 2010	Increase in Electric Rates in Remote Communities Served by Diesel Generation
1/11	January 4, 2011	New Electricity Rates in Remote Communities Served by Diesel Generation Effective January 1, 2011 to December 31, 2011 flowing from BO 134/10
148/11	October 20, 2011	Removal of the Residential Tail Block Effective November 1, 2011
116/12	August 29, 2012	Approval for September 1, 2012, 6.5% increase to full cost portion of the General Service and Government rates in the four remote communities served by diesel generation
117/12	August 31, 2102	Approval of September 1, 2012 Rate Schedules flowing from BO 116/12

PUB *Ex Parte* Orders		
Order No.	**Date**	**Surplus Energy Program**
43/13	April 26, 2013	Approval of Surplus Energy Program Option 1 Terms and Conditions
47/13	May 1, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
49/13	May 8, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
54/13	May 15, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
59/13	May 22, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
60/13	May 29, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
64/13	June 5, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
68/13	June 12, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1

PUB *Ex Parte* Orders		
Order No.	**Date**	**Surplus Energy Program**
71/13	June 19, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
72/13	June 26, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
74/13	July 3, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
76/13	July 10, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
78/13	July 17, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
83/13	July 24, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/13	July 31, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
90/13	August 7, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
95/13	August 14, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
97/13	August 21, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
99/13	August 28, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
104/13	September 4, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
108/13	September 11, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/13	September 18, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
115/13	September 25, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
118/13	October 2, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
120/13	October 9, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/13	October 16, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
131/13	October 23, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/13	October 30, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
135/13	November 6, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
137/13	November 13, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/13	November 20, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/13	November 27, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
146/13	December 4, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
152/13	December 11, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
155/13	December 18, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
156/13	December 24, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
157/13	December 31, 2013	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/14	January 8, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
5/14	January 15, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
10/14	January 22, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
11/14	January 29, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
14/14	February 5, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
18/14	February 12, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/14	February 19, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
21/14	February 26, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
24/14	March 5, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1

PUB *Ex Parte* Orders		
Order No.	**Date**	**Surplus Energy Program**
28/14	March 12, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
33/14	March 19, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
40/14	March 26, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
36/14	April 2, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
38/14	April 9, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
41/14	April 16, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
44/14	April 23, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/14	April 30, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
50/14	May 7, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
53/14	May 14, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
55/14	May 21, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/14	May 28, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
60/14	June 4, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
65/14	June 11, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/14	June 18, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
71/14	June 25, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
74/14	July 2, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
77/14	July 9, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
80/14	July 16, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
84/14	July 23, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/14	July 30, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
89/14	August 6, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/14	August 13, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
94/14	August 20, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
97/14	August 27, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
99/14	September 3, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
101/14	September 10, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
105/14	September 17, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/14	September 24, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/14	October 1, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
114/14	October 8, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/14	October 15, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
117/14	October 22, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/14	October 29, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
124/14	November 5, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
125/14	November 12, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
129/14	November 19, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
130/14	November 26, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1

PUB *Ex Parte* Orders		
Order No.	**Date**	**Surplus Energy Program**
134/14	December 3, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/14	December 10, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
142/14	December 17, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
144/14	December 23, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
147/14	December 31, 2014	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/15	January 7, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
5/15	January 14, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
6/15	January 21, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1

MANITOBA HYDRO

2015/16 & 2016/17 GENERAL RATE APPLICATION

PUBLIC UTILITIES BOARD MINIMUM FILING REQUIREMENTS

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MANITOBA HYDRO
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PUBLIC UTILITIES BOARD MINIMUM FILING REQUIREMENTS

11.0 OVERVIEW

Tab 11 includes responses to the Minimum Filing Requirements ("MFR") of the Public Utilities Board ("PUB") which was provided to interested parties on January 16, 2015. The MFRs are organized by category in the sections that follow. Where information has been incorporated in Tabs 3 to 10 of the Application, this has been identified in the sections below.

11.1 CORPORATE OVERVIEW

MFR #1:
Acknowledgment from Utility that all prior evidence from all prior Public Hearings is available to be used in the review of the current application before the Board.

Manitoba Hydro will address this issue at the Pre-Hearing Conference scheduled for February 5, 2015.

MFR #2:
Listing of past Board Directives and copies of all letters and reports to be in compliance with Board Directives

Tab 10 of Manitoba Hydro's Application provides a status update on PUB Directives from Orders 43/13, 134/10, and 150/08. Appendix 11.1 provides additional correspondence between Manitoba Hydro and the PUB related to Directive 12 of Order 43/13 (DSM Deferral Account).

MFR #3:

Provide an analysis which details all material changes in the Corporation operations since the last final Order of the Board.

A number of significant developments have taken place since the last Order of the PUB, including:

- In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19.
- In July 2014, the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20.
- As of April 2014, Manitoba Hydro's current Power Smart Plan targets the achievement of 1,136 MW and 3,978 GWh of savings over the next 15 years, and an investment of more than a billion dollars.
- Significant assets have been placed in-service, including the Pointe du Bois spillway replacement (August 2014) and the Riel 230/500kV Station (October 2014).
- Sustaining capital targets were established in CEF14 which considered increased requirements for aging infrastructure based upon asset condition assessments as well as requirements to support customer growth.
- Manitoba Hydro undertook an extensive review of its staff complement and is committed to reducing approximately 300 operational positions over the 3 year forecast period from 2014/15 to 2016/17. This cost saving measure will assist the Corporation in maintaining Operating, Maintenance & Administrative cost increases at an annual average increase of 1% per year (excluding accounting changes that impact OM&A) through fiscal 2016/17.

Manitoba Hydro-Electric Board's ("MHEB") Annual and Quarterly Reports also highlight significant accomplishments and events that are important to the operations of the Corporation.

MFR #4:

Corporate Organization chart indicating all affiliated Companies, subsidiaries, joint ventures and other ownership interests.

Please see Appendix 11.2.

MFR #5:
Detail of all related party transactions with Subsidiaries for the last three fiscal years.

Please see Appendix 11.3.

MFR #6:
Copies of Financial Statements for each of the subsidiaries MH has a material interest.

The financial statements for the 2012/13 and 2013/14 fiscal years for the following subsidiaries are provided in Appendix 11.4:

- Centra Gas Manitoba Inc. – audited
- Manitoba Hydro International Limited – audited
- Minell Pipelines Ltd. – audited
- Wuskwatim Power Limited Partnership – audited
- 5022649 Manitoba Ltd. (Wuskwatim Power General Partner) – unaudited
- Keeyask Hydropower Limited Partnership – audited
- 5900345 Manitoba Ltd. (Keeyask Power General Partner) – unaudited
- Manitoba Hydro Utility Services Limited – unaudited
- Teshmont Holdings LP Ltd. – unaudited
- 4985371 Manitoba Ltd. – unaudited
- 6690271 Manitoba Ltd. - unaudited (2013/14 only)

MFR #7:
Updated Ownership schematic for WPLP and KHLP.

Please see Appendix 11.5.

MFR #8:
Financial Forecasts for WPLP and KHLP.

Please see Appendix 11.6.

MFR #9:
Most Current Corporate Strategic Plan and report card similar to PUB/MH 1-6 (b) (2012 GRA).

Please see Appendix 2.1 of Tab 2 of the Application for Manitoba Hydro's most current Corporate Strategic Plan ("CSP"). Please see Figure 10.1 of Tab 10 for Manitoba Hydro's corporate dashboard comparing actual results against CSP targets for the 2013/14 fiscal year.

MFR #10:

Corporate Risk Analysis Report and Specific Risk Management Plans for all Major Risks including Drought.

Manitoba Hydro will provide a response to this MFR as Appendix 11.7, as soon as it is available.

11.2 FINANCIAL INFORMATION

MFR #1:

A 20 year IFF for electric operations only, indicating the respective financial targets.

MH14 can be found in Appendix 3.4 to the Application, including the financial ratios (electric only) for the 20 year forecast period.

MFR #2:

Summary of Reasons for Application Table of operating results (Tables 2.1.1, 2.1.2 2010 GRA) including ten years of record/ (7 years actual and current and test years) including the retained earnings for electric operations, and the financial targets, interest coverage, capital coverage and debt to equity ratio for electric operations only.

Please see Appendix 11.8.

MFR #3:

For the years 1999/00 through the test years, a details of rate increases requested, approved, the annual revenue increase and prevailing Manitoba CPI in similar basis to PUB/MH 1-2 (b) (2010 GRA).

Please see Appendix 11.9.

MFR #4:

Quarterly Financial Statements for the previous and current fiscal year.

Appendix 11.10 includes the following:

- The Manitoba Hydro-Electric Board ("MHEB") Annual Report for fiscal year ending March 31, 2013;
- The MHEB Quarterly Report for the three months ended June 30, 3013;
- The MHEB Quarterly Report for the six months ended September 30, 2013; and,
- The MHEB Quarterly Report for the nine months ended December 31, 2013.

The MHEB Annual Report for fiscal year ending March 31, 2014 can be found as Appendix 5.1 of the Application. The MHEB Quarterly Reports for the three months ending June 30, 2014, and the six months ending September 30, 2014 can be found as Appendix 5.2 and 5.3, respectively.

Manitoba Hydro will file with the PUB, the MHEB Quarterly Report for the nine months ended December 31, 2014 once it is publicly released, which is expected to be in late February 2015.

MFR #5:

A table, which details the debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings, DBRS bond ratings, total Provincial Debt and total MH debt to total Manitoba debt in each year since 1992.

Please see Appendix 11.11.

MFR #6:

A table, which details the debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings for each of the years in the 20-year electric IFF.

Please see Appendix 11.12.

MFR #7:
Details of the determination of each of the financial targets for the last five fiscal years and for each of the years in the 20 year forecast

Please see Appendix 11.13.

MFR #8:
Charts and respective data tables for each of the financial targets similar to PUB/MH I-30 (2012 GRA)

Please see Appendix 11.14.

MFR #9:
File 20 year IFF scenarios of revenue requirements/energy depicting post 2003 actual years to date plus future forecast cost components (Finance/Depreciation/Operating/Water Rentals/F&PP/Taxes) for:

- ***750 MW US lntertie project (CDN & US portions)***
- ***Keeyask generating station***
- ***Bipole Ill and Riel station***
- ***Pointe du Bois spillway & powerhouse***
- ***Wuskwatim overall project***
- ***Base Case (non-major) G+T+D revenue requirement***

Manitoba Hydro will provide a response to this MFR as Appendix 11.15, as soon as it is available.

MFR #10:
A schedule detailing General Consumer Revenue for 2005 through the test years detailing rate increases granted in similar format to PUB/MH 1-53 (2012 GRA).

Please see Appendix 11.16.

MFR #11:
A schedule detailing the statement of Income (Schedule 5.1.0, 2012 GRA) with five years historical through the forecast test years. The schedule should provide two columns for the compound annual growth rate for the historical period and for the

forecast period using the final year historical as a starting period. (On a similar basis as PUB/MH 1-52 (a) (2012 GRA)

Please see Appendix 11.17.

MFR #12:

A schedule detailing the actual MH Electric Operations financial statements (i.e. Operating Statement, Balance Sheet and Cash Flow Statement) for last five fiscal years in the same format as the IFF, including the actual electric financial ratios. (PUB/MH 1-51 2012 GRA)

Please see Appendix 11.18.

11.3 EXPORT AND DOMESTIC REVENUES

MFR #1:

File average unit revenue/cost calculation for 20 year IFF13 & IFF14 adding actual results for 2008/09, 2009/10, 2010/11, 2011/12, 2012/13 & 2013/14

Please see Appendix 11.19.

MFR #2:

File latest Power Resource Plans based on NFAT Plan 5 (2013/14 and 2014/15) Supply and Demand Tables:

- ***system power demand (MW) and dependable energy resources (GWh)/average energy resources at generation***
- ***system firm winter peak demand and capacity resources (MW) at generation***
- ***new system firm summer peak demand and capacity resources (MW) at generation***

System firm winter peak demand and capacity resources at generation, system firm energy demand and dependable resources at generation, and system firm energy demand and resources at generation (average of all flow conditions) can be found as Figures 9.1, 9.2 and 9.3, respectively, of Tab 9 of the Application. Manitoba Hydro does not produce firm summer peak and capacity resources demand and supply tables as requested in the MFR.

MFR #3:

Re-file Dec 2013 Revised PUB/MH 1-009 (2014 Interim) updated to end of 2014

- ***Monthly NEB data on firm/interruptible by export permit number plus imports***
- ***Separately summarizes summer and winter components for each year***

Please see Appendix 11.20 for the monthly NEB data on firm/interruptible by export permit number plus imports. Manitoba Hydro does not compile this information on a seasonal (summer and winter) basis.

MFR #4:

Re-file Dec 2013 Revised PUB/MH 1-008 (2014 Interim) updated to end of December 2014

- ***Total Sales Data (CON/US/Merchant)***
- ***Total MISO Sales (NEB Reporting)***
- ***Opportunity Export tables, separately showing summer and winter components for each year***
- ***Export Revenue tables showing Opportunity Bilateral, Day Ahead, Market, Real Time Market and Merchant Trading, separately showing summer and winter components for each year***
- ***Fuel and Power purchases showing system merchant purchases, import power purchases (without wind), wind energy purchases & fuel purchases***
- ***Transmission charges, separately showing summer and winter components for each year***

Information on total sales data and opportunity export sales can be found in Tab 9, Figures 9.6, 9.8 and 9.9. Information on NEB data on firm/interruptible exports by export permit number and imports can be found in the response to Domestic and Export Revenue MFR 3 and Appendix 9.1. Please see Appendix 11.21 for information on export revenue, fuel and power purchases and transmission charges.

Manitoba Hydro does not compile the information requested on a seasonal (summer and winter) basis.

MFR #5:

Re-file MH's response to Directive #5 of Board Order 43/13 updated to December 2014

- ***Hydraulic generation by watershed***
- ***Hydraulic Energy in Storage chart***
- ***Monthly river flows by watershed***
- ***Lake Winnipeg levels***

Please see Appendix 9.1 to Tab 9 of the Application.

MFR #6:
File updated 2012 GRA II-105 (PUB/MH II-105) quarterly report generation summaries

Please see Appendix 11.22.

11.4 OPERATING EXPENSES

MFR #1:
Schedule comparing the historical OM&A actual with IFF forecasts with explanations of variances

Please refer to Appendix 11.30.

MFR #2:
Details on all cost containment actions to reduce the growth in OM&A over the last five fiscal years and forecast through the test years.

Please see Tab 5, Section 5.14 for details of cost containment measures being undertaken by the Corporation.

MFR #3:
EFT staffing level information for the last five fiscal years and that forecast through the test years by business unit.

Please see Appendix 11.23.

MFR #4:

Schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 2003/04 through the test years. This analysis should include the total labour and benefits capitalized for each year, total labour and benefits and the percentage of labour and benefits capitalized in a similar level of detail of PUB/MH l-5(c) R & PUB/MH 11-2 from the 2010 GRA.

Please see Appendix 11.24.

MFR #5:

Schedule that average salary per EFT by business unit for the last five fiscal years through the test years.

Please see Appendix 11.25.

MFR #6:

Provide details of the contracted wage settlements currently in place.

Please see pages 3 and 4 of Appendix 5.5 of the Application.

MFR #7:

Schedule of FTE by Business Unit from 2007/08 through the test years.

Please refer to Appendix 11.23.

MFR #8:

A table/ matrix of EFT per 1,000 of GWh, per $millions of domestic revenue, per domestic customers for the years 2007/08 through the test years in a similar format to PUB/MH I-38 (a) (2012 GRA).

Please see Appendix 11.26.

MFR #9:
Schedule detailing the breakdown of Operating and Administrative expenses by division from 2003/04 through the test years. On this schedule provide two columns for the compound annual growth rate for the historical period and for the forecast period using the final year historical as a starting period. (PUB/MH 1-59 (b) - 2012 GRA)

Please see Appendix 11.27.

MFR #10:
Schedule detailing the capitalized OM&A costs by business unit for the years 2003/04 through the test years.

Please see Appendix 11.28.

MFR #11:
A comparison of the OM&A per customer for actual and current IFF with that presented at last GRA for comparable years for each year through the test years. (PUB/MH I-8 (c) 2010 GRA)

Please see Appendix 11.29.

MFR #13: (Please note the PUB did not provide an MFR #12)
A schedule which compares Operating, Maintenance and Administrative Cost for fiscal years subject to last GRA to actual results presented in this application with the forecast results provided at the Prior GRA in both dollar change and % change by:

- ***Cost element***
- ***Business unit***
- ***And explain any differences over 5%.***

Please see Appendix 11.30.

MFR #14:
A schedule detailing the operating and administration charged to Centra and Other Affiliates for each of the last five fiscal years through the test years (actual/forecast) by:

- ***Cost Element***
- ***Business Unit***

Manitoba Hydro will provide a response to this MFR as Appendix 11.31, by the end of February.

11.5 PAYMENTS TO GOVERNMENT

MFR #1:
A schedule of actual and forecast payments made to the Province and Municipalities for five historical years and for the 20-year forecast period.

Please see Appendix 11.32.

MFR #2:
A schedule detailing the calculation of the Net Hydro Guarantee fee for five historical years and through the twenty year forecast period. (Similar to PUB/MH 1-24 (b) 2010 GRA)

Please see Appendix 11.33.

MFR #3:
A schedule detailing the calculation of the water rental payments for the last five historical years and through the twenty year forecast period. (Similar to PUB/MH 1-24 (c) 2010 GRA)

Please see Appendix 11.34.

11.6 CAPITAL EXPENDITURES-DEPRECIATION

MFR #1a:
File the most recent Capital Expenditure Forecast, identifying material changes to major and base capital forecasts.

Please see Appendix 4.1 for Manitoba Hydro's Capital Expenditure Forecast (CEF 14). Tab 4, Sections 4.2 to 4.4 outlines major changes to the capital forecast.

MFR #1b:

File a detailed breakdown and justification of any cost revisions to the major capital projects (including Bipole III) that have occurred since the last CEF.

Please see Tab 4, section 4.3 for a summary of cost updates with respect to the significant major new generation and transmission projects and electric demand side management. CEF 14, in Appendix 4.1 of the Application, provides updates for each of the major new generation and transmission projects, and major projects.

MFR #2:

A schedule detailing the breakdown of the balances by component of capitalized costs (wages, overhead etc.) in construction work and process, for each major Generation and Transmission project consistent with the last Annual Report.

Please see Appendix 11.35.

MFR #3:

Provide a breakdown of the total balance of Generation & Transmission costs by each major project and identify the balance related to base capital, in a similar level of detail is PUB/MH I- 45 (b).

Please see Appendix 11.36.

MFR #4:

A schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance each Major Generation & Transmission Projects in each of the forecast years and the (electric) capital coverage ratio for the last five historical years and through the 20 year forecast period in a similar format to PUB/MH 1-22 (c) from the 2012 GRA.

Please see Appendix 11.37.

MFR #5:

File 2014 20 year Electric Capital Expenditure forecasts for: NFAT Plan 5

Per clarification from PUB counsel, NFAT Plan 5 was intended to request Manitoba Hydro’s current Capital Expenditure Forecast (CEF 14) which is provided as Appendix 4.1.

MFR #6:
File Asset Condition reports as directed by Board.

- ***Generation***
- ***Transmission***
- ***Distribution***

Please see Appendix 4.2 for the Corporation’s electric infrastructure assessment condition report.

MFR #7:
File alternative depreciation approaches:

- ***Average Service Life (ASL)***
- ***Equal Group Life (EGL)***

Manitoba Hydro has previously advised the PUB that it is not able to provide a comparison of ELG and ASL IFRS compliant depreciation rates based on a full ASL depreciation study. As such, Manitoba Hydro has been working on an alternate approach that does not require a full ASL depreciation study, but would demonstrate the impacts of using ELG versus ASL methodologies. Manitoba Hydro anticipates filing a response with respect to these Directives by the end of February.

11.7 FINANCE EXPENSE-DEBT LEVELS

MFR #1:
Table(s) detailing the relied upon interest forecasts by forecaster for both short term and long term interest rates indicating, the date of the forecast, whether the forecast represented end of period data or average and describe what if any adjustments were made to end of period data forecasts to average the results.

Please see Appendix 3.2 of Tab 3 of the Application.

MFR #2:
Copies of the current Economic Outlook.

Please see Appendix 3.1 of Tab 3 of the Application for the 2014 Economic Outlook (EO14).

MFR #3:
Copies of all interest forecasts relied upon for preparing interest rate forecasts

Please see Appendix 3.2 of Tab 3 of the Application.

MFR #4:
A schedule that details for the last five fiscal year through the 20 year current forecast a summary of total interest and finance cost incurred/ forecasted by major category [debt charges, foreign currency gains/losses etc.] both capitalized and expended in a similar level of detail provided in PUB/MH 1-35 (2010 GRA).

Please see Appendix 11.38.

MFR #5:
A continuity schedule of the short and long-term debt for the fiscal years 2004 to 2032 detailing the retirement of existing debt and the issue of new debt, include the debt ratio. Indicate the proportion of short-term debt to total debt for each of the years.

Please see Appendix 11.39.

MFR #6:
Term sheets related to long term debt issued in the last two fiscal years.

Please see Appendix 11.40.

MFR #7:
A schedule detailing the maturities of MH's current long-term debt issues. (PUB/MH 1-67 (f) 2012 GRA)

Please see Appendix 11.41.

MFR #8:

A schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions of debt maturing in 10 years, 20 years and greater than 20 years.

Please see Appendix 11.42.

MFR #9:

Current Credit Rating Reports for Manitoba Hydro and the Province.

Please see Appendix 3.8 to Tab 3 of the Application.

11.8 DSM

MFR #1:

A continuity schedule showing spending, amortization expense, amortization rates and balances for demand side management for the years 2004/05 through the test years.

Please see Appendix 11.43.

MFR #2:

An update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs, including a continuity schedule of program spending since inception.

Please see Appendix 11.44.

MFR #3:

File Inverted Rate Strategy plan of MH as directed by Board.

- ***Non-electric Heating Customers***
- ***Electric Heating Customers***

As identified in Appendix A.2 of Manitoba Hydro's 2014-17 Power Smart Plan – 15 year supplementary report (Appendix 8.1 to the Application), conservation (or inverted) rates are under consideration by Manitoba Hydro.

Manitoba Hydro is not in a position to advance an inverted rate strategy during this proceeding.

11.9 LOAD FORECAST AND POWER SMART PLANS

MFR #1:

File most current Corporate Approved 2014 Load Forecast and Power Smart Plan

- ***With Base Case DSM***
- ***With Level 2 DSM***

The 2014 Electric Load Forecast can be found as Appendix 7.1 of Tab 7 of the Application. The 2014-17 Power Smart Plan can be found as Appendix 8.1 of Tab 8 of the Application.

MFR #2:

File tabular 12SEP actual load profiles as per PCOSS14 Schedule D-2 for F2009 to F2014 separately depicting

- ***Domestic Load by subclass***
- ***Firm Exports (5x16)***
- ***Peak Opportunity Exports (5x16)***
- ***Weekend Exports (2x16)***
- ***Off-peak Exports (7x8)***

Manitoba Hydro is seeking clarification from the PUB Advisors on this MFR. The response will be provided as Appendix 11.45 when available.

MFR #3:
Re-File NFAT-MH Exhibits #176-1 and #176-2 Domestic & Export Transmission Losses

Please see Appendix 11.46.

MFR #4:
Re-file Power Resource Plan Supply and Demand tables for average energy resources using progressive Incremental (12R)Transmission losses for:

- ***Domestic Load summer and winter (separately) w/o exports***
- ***Adding Peak (5x16) Exports summer and winter (separately)***
- ***Further adding Off-peak Opportunity Exports summer and winter (separately)***

Manitoba Hydro is seeking clarification from the PUB Advisors on this MFR. The response will be provided as Appendix 11.47 when available.

MFR #5:
Re-file SEP modifications (as updated)

Please see Tab 6, Section 6.4 of the Application.

MFR #6:
Re-file TOU proposal (as updated)

Please see Tab 6, Section 6.3 of the Application.

Manitoba Hydro

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March 25, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

RE: Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 re: Demand Side Management Expenditures

Manitoba Hydro and Centra Gas Manitoba Inc. ("Centra") require confirmation from the Public Utilities Board of Manitoba ("PUB") with respect to the Corporation's interpretation and intended accounting treatment of Directive 12 from Order 43/13 and Directive 1(d) from Order 85/13 related to the Demand Side Management ("DSM") spending in 2012/13 and 2013/14.

Directive 12 of Order 43/13

On April 26, 2013, the PUB issued Order 43/13 with respect to Manitoba Hydro's 2012/13 & 2013/14 General Rate Application ("GRA"). Directive 12 of Order 43/13 states:

> *"That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application."*

In Directive 12 from Order 43/13, the DSM spending amounts identified by the PUB of $34.4 million in 2012/13 and $34.7 million in 2013/14 were determined based on the level of forecast electric Power Smart spending in the 2011 Power Smart Plan. These amounts did not include the forecast Affordable Energy Fund ("AEF") spending.

Manitoba Hydro filed IFF12 as part of the 2012/13 & 2013/14 GRA, which included an updated Electric Power Smart budget, as follows:

Table 1: Electric DSM Budget 2012 Capital Expenditure Forecast			
($millions)	2012/13	2013/14	Total
Electric Power Smart	$28.5	$28.0	$56.5

The Corporation's investment in DSM is deferred and amortized over a period of 10 years commencing in the year after the costs are incurred. The amortization of these costs are then included in the annual depreciation and amortization expense in revenue requirement. Accordingly, the amount of DSM included in Manitoba Hydro's revenue requirement for the purpose of setting rates includes the amortization of DSM expenditures from prior periods; not the forecast level of Power Smart spending in the test year.

As such, Manitoba Hydro interprets Directive 12 of Order 43/13 as requiring the difference between the amortization of the forecast Electric Power Smart amounts included in revenue requirement and the amount of actual spending that will be reflected in amortization expense for financial reporting purposes to be captured in a deferral account. The following table shows the difference between the amount of forecast DSM spending reflected in revenue requirement for the 2013/14 test year, and the actual level of DSM spending that will be reflected in amortization expense for financial reporting purposes. The amounts to be included in a deferral account, in accordance with Manitoba Hydro's interpretation of Directive 12 of Order 43/13, is $0.19 million.

Table 2: Electric Power Smart Deferral Account ($millions)	
Amortization of Forecast DSM spending for 2012/13 included in 2013/14 Test Year Revenue Requirement[1]	$2.85
Amortization of of actual DSM spending for 2012/13 included in 2013/14 amortization expense for financial reporting purposes[2]	$2.66
Amount to be included in deferral account	**$0.19**

[1]Represents one-tenth of the 2012/13 forecast spending of $28.5 million
[2]Represents one-tenth of 2012/13 actual Electric Power Smart Spending of $26.6 million

In future General Rate Applications, the amortization of the actual Electric Power Smart spending for 2012/13 and 2013/14 will be reflected in DSM amortization expense and as such, there will be no further differences between forecast amounts included in revenue requirement and actual spending.

Manitoba Hydro requests the PUB's confirmation of its interpretation of Directive 12 of Order 43/13 and notes that the PUB will have further opportunity to consider the disposition of this deferral account at Manitoba Hydro's next General Rate Application.

Directive 1(d) of Order 85/13

The PUB provided a similar directive for the natural gas operations in Order 85/13 which was issued with respect to Centra's 2013/14 GRA. Directive 1(d) of Order 85/13 states:

> *"Centra's revenue requirement is determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart Plan of $19.3 million for 2013/14. To the extent Centra's spending on Demand-Side Management in the Test Year, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $19.3 million, Centra shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application."*

In Directive 1(d) from Order 85/13, the DSM spending amounts were determined based on the level of forecast gas DSM spending in the 2011 Power Smart Plan, as follows:

Table 3: Gas DSM Budget 2011 Power Smart Plan	
($millions)	**2013/14**
Gas Power Smart	$13.5
Affordable Energy Fund	$3.5
Furnace Replacement Program	$2.3
Total	**$19.3**

Centra notes that the $19.3 million represents the total natural gas DSM forecast spending for 2013/14, including the AEF and Furnace Replacement Program ("FRP"). As a point of clarification, the above amounts were not included in Centra's 2013/14 revenue requirement. Rather, for the purposes of setting natural gas rates, the amount of DSM included into Centra's revenue requirement is the amortization of DSM expenditures from prior periods. Centra's rates for the Small General Service class also includes $3.8 million to fund the FRP.

The forecast AEF expenditures for both electric and natural gas are amortized to the electric operations only, since the fund was established by *The Winter Heating Cost Control Act* based on a percentage of Manitoba Hydro's 2006/07 gross electricity export revenues. As such, the AEF amortization is allocated to the electric operations only and is not included in Centra's revenue requirement.

With respect to the FRP, Centra has collected approximately $3.8 million in each year since 2007/08 to fund the FRP, as directed by the PUB. All amounts collected for the FRP are maintained in the FRP fund to finance program expenditures.

Since the amortization of DSM expenditures commences the year after the costs are incurred, Centra's revenue requirement for the 2013/14 test year did not include any of the forecast Natural Gas Power Smart spending for 2013/14. Given that the DSM amounts included in Centra's rates is the amortization of prior period DSM expenditures, and that Centra's revenue requirement does not include any amortization of the AEF, there are no amounts to capture in a deferral account. Centra will continue to maintain the amounts collected for the FRP in a deferral account to fund related program expenditures. As such, Centra already maintains a liability account on its balance sheet which reflects the actual total FRP funding to date less the actual expenditures made from the fund.

Manitoba Hydro respectfully requests the PUB's confirmation of its interpretation of Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 by April 11, 2014, in order for the Corporation to advance related year-end auditing processes in a timely manner. Should you have any questions with respect to this submission, please contact the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent Czarnecki
Barrister & Solicitor

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May 15, 2014

Mr. Brent Czarnecki
Law Department
Manitoba Hydro
22nd floor
360 Portage Avenue
Winnipeg MB R3C 0G8

Dear Mr. Czarnecki:

RE: Manitoba Hydro - DSM Spending

On March 25, 2014, Manitoba Hydro requested confirmation from the Board that Manitoba Hydro correctly interpreted Directive 12 from Order 43/13 and Directive 1(d) from Order 85/13. Manitoba Hydro's interpretation does not agree with the Board's direction. The Board provides clarification of its direction as follows.

At the last electric GRA, the Board expressed a concern that less was being spent on DSM than that set out in the 2011 Power Smart Plan: $34.4 million in 2012/13 and $34.7 million in 2013/14 or $69.1 million for the two test years. During the GRA, Manitoba Hydro filed an updated forecast of DSM spending of $56.5 million, or $12.5 million less over the two years.

The Board directed:

> *" That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application."* [Order 43/13 Directive 12]

The Board clarifies that Manitoba Hydro is to establish a deferral account that captures the difference between the budgeted level of DSM spending from the 2011 Power Smart Plan and the actual spending by Manitoba Hydro. With respect to 2012/13, the budgeted amount was $34.4 million while the actual spending was $26.6 million. The difference of $7.8 million should accrue to the deferral account. Likewise, the difference between actual spending in 2013/14 and the budgeted spending in the 2011 Power Smart Plan of $34.7 million should accrue to the deferral account.

The Board directs a similar treatment of DSM expenditures for Centra. The DSM spending forecasted in the 2011 Power Smart Plan for gas DSM programs in 2013/14 was $19.3 million including the AEF and Furnace Replacement Program. The forecasted spending in the 2011 Power Smart Plan minus the AEF and FRP was $13.5 million. The Board directs that any difference between actual spending on gas DSM programs and the $13.5 million forecasted spending is to accrue to the DSM deferral account.

The Board understands that Manitoba Hydro is forecasting increased levels of DSM savings and investment in its 2014-2017 Power Smart Plan. The Board is encouraged by the planned increased level of investment and looks forward to reviewing the new Power Smart Plan at upcoming General Rate Applications. At that time the Board will consider the continued need for the DSM deferral account in the context of Manitoba Hydro’s new Power Smart Plan.

Sincerely,

“Original Signed By”

Kurt Simonsen, P. Eng.
Associate Secretary

KS/nac

c.c. Mr. Bob Peters, Board Counsel
Ms. Odette Fernandes, Manitoba Hydro

Manitoba Hydro

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May 23, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

RE: Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 re: Demand Side Management ("DSM") Expenditures

Further to the Public Utilities Board's ("PUB") letter of May 15, 2014, Manitoba Hydro wishes to obtain confirmation of the appropriate accounting treatment of the PUB's DSM Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 for the purposes of it financial statements as at March 31, 2014.

Considering the clarification provided by the PUB in the letter, Manitoba Hydro can advise that the cumulative amount of the differences between actual and forecast DSM spending to March 31, 2014 associated with the directives is approximately $15 million related to electric operations and $5 million related to gas operations. The total for consolidated operations is approximately $20 million.

Manitoba Hydro has considered two alternate accounting treatments to reflect the PUB's DSM directives in its financial statements:

1. Record the cumulative DSM spending differences as a regulated liability and a corresponding Power Smart regulated asset; or,
2. Record the cumulative DSM spending differences as a regulated liability and a corresponding reduction of 2013/14 net income.

The focus of the PUB in its clarifying letter of May 15, 2014 is in maintaining a level of total spending on DSM programs to target higher levels of domestic customer energy savings rather than the mechanics of how DSM spending is ultimately amortized into rates and net income (which was provided in Manitoba Hydro's letter of March 25, 2014). Accordingly, Manitoba Hydro believes that the first alternative is the most appropriate accounting treatment under the circumstances and requests that the PUB provide written confirmation that it is consistent with the intent of the DSM directives. Manitoba Hydro further notes that the PUB will consider the disposition of these deferred amounts at the next General Rate Application.

Given that the amounts in question are material to the financial statements and that the Corporation is nearing the end of its year-end audit process and a closing meeting is scheduled with the external auditors for Thursday, May 29, 2014, Manitoba Hydro respectfully requests that confirmation be provided by the PUB in advance of that date.

Yours truly,

MANITOBA HYDRO LAW DIVISION

Per:

Rebecca Hutchings
Barrister & Solicitor

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May 28, 2014

Rebecca Hutchings
Law Department
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22nd floor
360 Portage Avenue
Winnipeg MB R3C 0G8

Dear Ms. Hutchings:

RE: Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 re Demand Side Management (DSM) Expenditures

The Board is in receipt of your letter dated May 23, 2014 seeking confirmation of the appropriate accounting treatment of the PUB's DSM Directive 12 of Order 43/13 and Directive 1(d) of Order 85/13 for the purposes of it financial statements as at March 31, 2014.

The Board notes that, it does not in due course, dictate the accounting treatment related to directives of Manitoba Hydro (MH), however the Board appreciates Manitoba Hydro seeking the Board's input on this issue. The Board relies on the Financial Statements of the Corporation in assessing rate adequacy and supports accounting treatment that are consistent with the economic effect and intent of the Board's directives. The Board's preference is that the transaction be consistent with the intent of its directive of maintaining a level of total DSM program spending consistent with the 2011 Power Smart Plan to target higher levels of domestic customer energy savings.

The Board believes that MH's proposed accounting to establish a regulated asset to track the unspent DSM program monies and to establish a corresponding regulated liability is consistent with the Board's intent under the circumstances.

...2

The Board notes that MH has recently indicated higher planned DSM spending in its 2014 Power Smart Plan. The Board will review the matter of DSM spending at the upcoming General Rate Application and will assess the status of the regulated asset and liability at that time.

If there is a need for further clarification of this matter please do not hesitate to contact the undersigned.

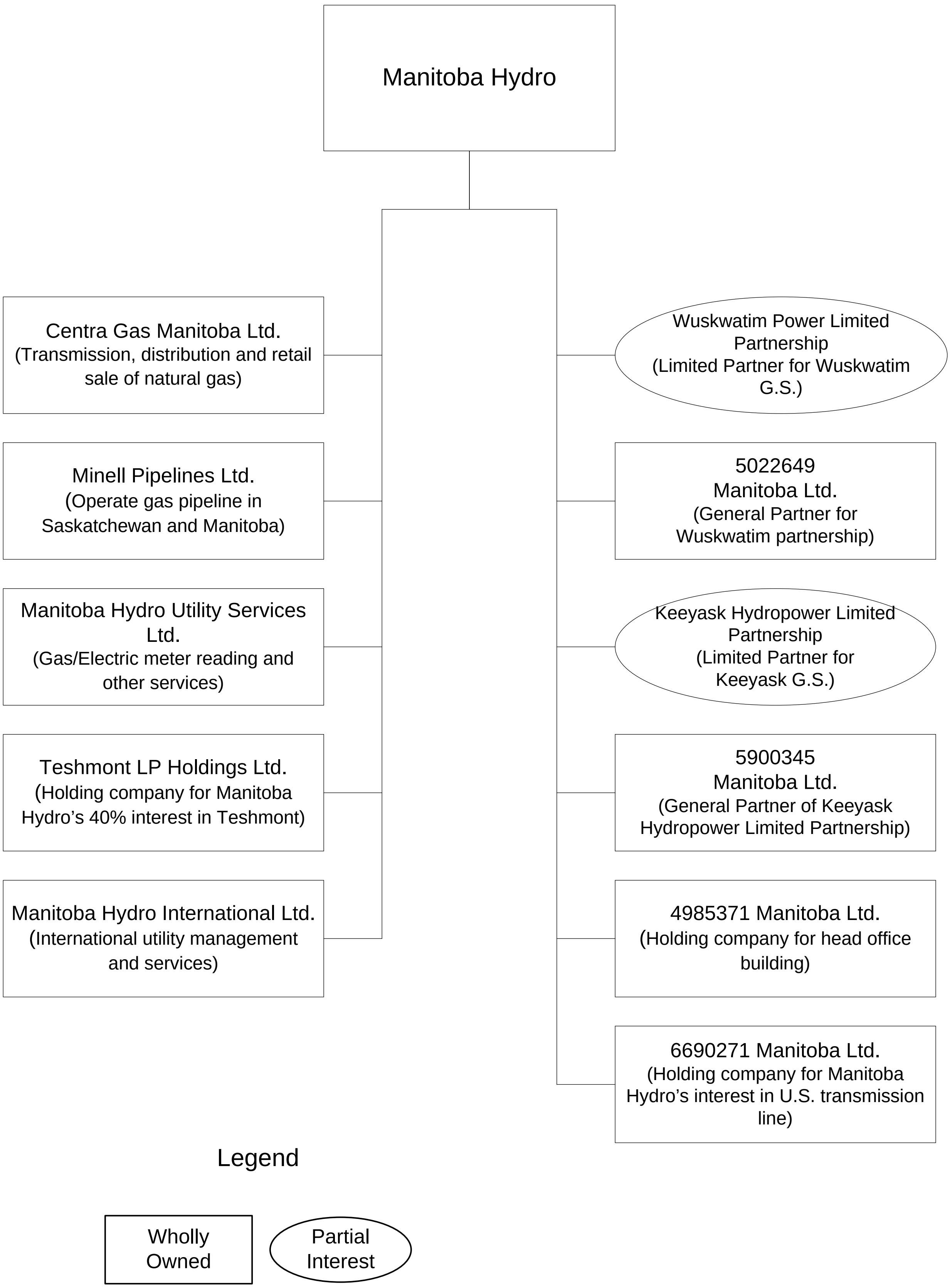
Sincerely,

"Original Signed By"

Hollis Singh
Secretary

HS/nac

c.c. Mr. Bob Peters, Board Counsel


Manitoba Hydro
Centra Gas Manitoba Ltd. (Transmission, distribution and retail sale of natural gas)
Minell Pipelines Ltd. (Operate gas pipeline in Saskatchewan and Manitoba)
Manitoba Hydro Utility Services Ltd. (Gas/Electric meter reading and other services)
Teshmont LP Holdings Ltd. (Holding company for Manitoba Hydro's 40% interest in Teshmont)
Manitoba Hydro International Ltd. (International utility management and services)
Wuskwatim Power Limited Partnership (Limited Partner for Wuskwatim G.S.)
5022649 Manitoba Ltd. (General Partner for Wuskwatim partnership)
Keeyask Hydropower Limited Partnership (Limited Partner for Keeyask G.S.)
5900345 Manitoba Ltd. (General Partner of Keeyask Hydropower Limited Partnership)
4985371 Manitoba Ltd. (Holding company for head office building)
6690271 Manitoba Ltd. (Holding company for Manitoba Hydro's interest in U.S. transmission line)
Legend
Wholly Owned
Partial Interest

Corporate Overview MFR 5

Detail of all related party transactions with Subsidiaries for the last three fiscal years.

Summaries of all related party transactions between Manitoba Hydro and affiliated entities are provided below. All amounts are provided in thousands of dollars unless otherwise noted.

Minell Pipelines Ltd.

The services provided by Manitoba Hydro to Minell Pipelines consist mainly of labour such as general pipeline maintenance. Minell has a line of credit arrangement with Manitoba Hydro. Funds advanced under this agreement have no fixed terms of repayment and bear interest at the average one-month banker's acceptance rate.

	2011/12	2012/13	2013/14
Activities charged by MH	9	39	64
Interest charged by MH	18	17	14
Advance from Parent	1 046	1 117	1 725

Teshmont Holdings Inc.

Teshmont Holdings Inc. was established as a holding company to acquire a 40% ownership of Teshmont Consultants Limited Partnership (TCLP). Teshmont Consultants Limited Partnership provides engineering related consulting services to Manitoba Hydro.

	2011/12	2012/13	2013/14
Consulting Services	6 795	5 280	3 592

Manitoba Hydro Utilities Services (MHUS)

MHUS provides Manitoba Hydro and its wholly owned subsidiary Centra Gas Manitoba Inc. with meter reading, interactive voice response systems and other contracted services. The General Manager and the Finance & Administration Coordinator are seconded from Manitoba Hydro. MHUS is charged for these positions consistent with charges for seconded employees. MHUS leases its premises from Manitoba Hydro, and is charged on a cost recovery basis.

	2011/12	2012/13	2013/14
Admin expense charged by MH	287	266	212
Services provided to MH	5 428	4 618	4 909
Rent charged by MH	12	12	15

Manitoba Hydro International (MHI)

MHI currently has four business segments, International Utility Services, Manitoba HVDC Research Centre, W.I.R.E. Services and Telecom Services. International Utility Services provides professional consulting, training and electricity infrastructure management services primarily to developing markets. The Manitoba HVDC Centre provides technology products, research and development and engineering services to the electrical power system industry. W.I.R.E. Services provides aerial LiDAR data collection and analysis to determine transmission line thermal ratings. Telecom Services provides state of the art broadband telecommunication solutions for telecom carriers, internet service providers and large commercial customers.

The staffing provided by Manitoba Hydro for the execution of contracts and management of its operations is billed to MHI consistent with charges for seconded employees. During the normal course of business, MHI provides services to Manitoba Hydro and MHI pays for the rental of fibre strands from Manitoba Hydro.

	2011/12	2012/13	2013/14
Payroll charged by MH	1 771	2 336	2 302
Fibre rental charged by MH	464	475	521
Services charged to MH	1 965	5 264	3 105

Centra Gas Manitoba Inc.

Centra's short-term funding is financed by Manitoba Hydro with interest calculated monthly at floating rates with no fixed repayment terms. Manitoba Hydro has also provided long-term advances to Centra Gas with various interest rates and repayment terms. The following amounts are provided in millions of dollars.

	2011/12	2012/13	2013/14
Operating & Admin charged by MH	62	64	67
Interest charged by MH	19	18	16
Common asset depreciation to Centra	5	6	5
Common asset depreciation from Centra	1	1	1
Due to Parent	14	26	34
Long term debt	298	295	305

Wuskwatim Power Limited Partnership (WPLP)

The Wuskwatim Power Limited Partnership was formed on December 9, 2004 to carry on the business of developing, owning and operating the Wuskwatim hydroelectric generating station and related works excluding the transmission facilities but including all dams, dikes, channels, excavations and roads to be located at Taskinigahp Falls near Wuskwatim Lake.

WPLP has entered into various agreements with Manitoba Hydro to provide services to the partnership. The following agreements are currently in effect:

a) the Construction Agreement, whereby Manitoba Hydro will construct the Wuskwatim Generating Station and related works;

b) the Interconnection and Operating Agreement, whereby Manitoba Hydro will connect the Wuskwatim generating station to Manitoba Hydro's integrated power system;

c) the Management Agreement, whereby Manitoba Hydro will provide administrative and management functions to WPLP; and

d) the Project Financing Agreement, whereby Manitoba Hydro will provide debt financing to WPLP.

The following amounts are in millions of dollars:

	2011/12	2012/13	2013/14
Amounts paid to MH - Construction Agreement	156	87	22
Amounts paid to MH - Interconnection	27	14	(1)
Amounts paid to MH - Management Agreement	3	3	1
Amounts received from MH - Power Purchase Agreement	-	25	47
Operating & Admin charged by MH	-	5	11
Interest charged by MH	-	41	71
Water rentals charged by MH	-	3	5
Long term debt (due to MH)	1 201	1 288	1 350
Interest payable on long term debt	17	16	17
Equity contributions received from MH and the GP	26	16	2

Financial Statements

Centra Gas Manitoba Inc.

March 31, 2013

ERNST & YOUNG

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Centra Gas Manitoba Inc.

We have audited the accompanying financial statements of **Centra Gas Manitoba Inc.**, which comprise the balance sheet as at March 31, 2013 and the statements of income (loss), retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Centra Gas Manitoba Inc.** as at March 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Winnipeg, Canada,
June 26, 2013.

CENTRA GAS MANITOBA INC.

STATEMENT OF INCOME (LOSS)

For the year ended March 31

	Notes	2013	2012
		millions of dollars	
Revenues			
Commodity		**182**	197
Distribution		**146**	131
		328	328
Cost of gas sold		**182**	197
		146	131
Other income		**1**	1
		147	132
Expenses			
Operating and administrative	3	**64**	62
Finance expense	3 & 4	**18**	19
Depreciation and amortization		**27**	26
Capital and other taxes		**18**	19
Corporate allocation	5	**12**	12
		139	138
Net Income (Loss)		**8**	(6)

The accompanying notes are an integral part of the financial statements.

STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2013	2012
	millions of dollars	
Retained earnings, beginning of year	**34**	40
Net income (loss)	**8**	(6)
Retained earnings, end of year	**42**	34

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
BALANCE SHEET
As at March 31

	Notes	2013	2012
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	6	**661**	637
Less accumulated depreciation	6	**232**	224
		429	413
Construction in progress	6	**2**	2
		431	415
Current Assets			
Accounts receivable and accrued revenue		**76**	47
Gas in storage		**21**	41
		97	88
Other Assets			
Regulated assets	7	**78**	77
Intangible assets	8	**8**	8
		86	85
		614	588
Liabilities and Shareholder's Equity			
Long-Term Debt	9	**295**	235
Current Liabilities			
Due to parent	10	**26**	14
Accounts payable and accrued liabilities	11	**76**	70
Current portion of long-term debt	9	**-**	63
		102	147
Other Liabilities			
Refundable advances from customers		**21**	18
		21	18
Contributions in Aid of Construction		**33**	33
Shareholder's Equity			
Share capital	14	**121**	121
Retained earnings		**42**	34
		163	155
		614	588

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

CENTRA GAS MANITOBA INC.
STATEMENT OF CASH FLOWS
For the year ended March 31

	2013	2012
	millions of dollars	
Operating Activities		
Cash receipts from customers	**294**	389
Cash paid to suppliers	**(239)**	(320)
Interest paid	**(20)**	(20)
Cash provided by operating activities	**35**	49
Financing Activities		
Long-term repayments to parent	**(63)**	-
Long-term advances from parent	**60**	-
Short-term advances from (repayments to) parent	**12**	(6)
Cash provided by (used for) financing activities	**9**	(6)
Investing Activities		
Property, plant and equipment, net of contributions	**(34)**	(31)
Other	**(10)**	(12)
Cash used for investing activities	**(44)**	(43)
Net change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**-**	-

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 1 SIGNIFICANT ACCOUNTING POLICIES

Nature of the Organization – Centra Gas Manitoba Inc. (Centra) distributes natural gas to more than 269 000 residential, commercial and industrial customers throughout Manitoba. Centra delivers natural gas to its customers through a network of transmission pipelines and distribution mains totaling approximately 9 300 kilometers in length. Centra is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro) and is regulated by the Public Utilities Board of Manitoba (PUB).

Basis of Presentation – The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Canadian Institute of Chartered Accountants (CICA) Accounting Handbook, "Pre-Changeover Accounting Standards" and include the significant accounting policies described hereafter.

Rate-Regulated Accounting - The prices charged for the sale of natural gas within Manitoba are subject to review and approval by the PUB. The rate-setting process is designed such that rates charged to gas customers recover all costs incurred in providing gas service to customers. As permitted under GAAP, Centra applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Centra applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise be included in the determination of net income in the year that the cost or credit is incurred. Centra refers to such deferred costs or credits as regulated assets (Note 7) or regulated liabilities (Note 11) which are generally comprised of the following:

- Power Smart programs - The costs of Centra's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.

- Deferred taxes - As a result of its acquisition by Manitoba Hydro in 1999, Centra became non-taxable and, in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.

- Site restoration costs - Site restoration costs incurred are deferred and amortized on a straight-line basis over a period of 15 years.

- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.

- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

charged to customers as approved by the PUB. The difference between the recorded cost of natural gas and the actual cost of natural gas is carried as an account receivable/payable and recovered or refunded in future rates.

Centra's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Property, plant and equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases and depreciation and interest charged to operations commences.

b) **Depreciation**
Depreciation is provided on a straight-line remaining-life basis. The range of estimated service lives of each major asset category is as follows:

Distribution	5 - 65 years
General plant	10 - 45 years

Provision for removal costs of major property, plant and equipment is charged to depreciation expense on a straight-line basis over the remaining service lives of the related assets. Retirements of these assets, including costs of removal, are charged to accumulated depreciation with no gains or losses reflected in operations. The estimated service lives and removal costs of the assets are based upon depreciation studies conducted periodically by Centra.

c) **Intangible Assets**
Intangible assets include computer application development costs and land easements. Intangible assets are recorded at cost. The cost of computer application development includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Intangible assets with finite useful lives are amortized over their useful lives on a straight-line basis. The expected useful lives are as follows:

Computer application development	10 years
Land easements	75 years

The estimated service lives of intangible assets are based upon depreciation studies conducted periodically by Centra.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

d) **Contributions in Aid of Construction**
Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

e) **Gas in Storage**
Gas in storage is valued at average cost.

f) **Revenues**
Customers' meters are read and billed on a cyclical basis. Revenues are accrued in respect of energy delivered for those cycles not yet billed.

g) **Cost of Gas Sold**
Cost of natural gas sold is recorded at the same rates charged to customers.

h) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities. Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in income in the period in which they arise.

i) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). As Centra has no items related to OCI, comprehensive income for the year is equivalent to net income.

j) **Foreign Currency Translation**
Current monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at the exchange rate prevailing at the balance sheet date. Gains or losses related to natural gas storage purchases which arise from the date of receipt to date of payment are included as inventoried cost. All other exchange gains and losses on the translation of current monetary assets and liabilities are credited or charged to finance expense in the current period.

k) **Derivatives**
Centra does not engage in derivative trading or speculative activities. Centra mitigates natural gas price volatility to customers through the use of natural gas price swaps. Fixed price swaps are carried at fair value on the balance sheet with gains and losses recorded in income.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

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l) **Debt Discounts and Premiums**
Debt discounts and premiums are amortized to finance expense using the effective interest method.

m) **Use of Estimates**
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual amounts could differ from those estimates, but differences are not expected to be material.

NOTE 2 ACCOUNTING CHANGES

Overhead Rate Estimate
Centra's policy is to include a proportionate share of overhead costs in property, plant and equipment based on overhead rate studies that are performed annually. In 2012, Centra revised its overhead rate estimate to remove information technology infrastructure and related support costs and common building depreciation and operating costs. This change in estimate was applied prospectively effective April 1, 2012 and resulted in a $2 million increase in operating and administrative expense in 2012-13.

Future Accounting Changes

International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Centra would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Centra include property, plant and equipment, regulatory assets and liabilities and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS.*

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus *Improvements to IFRS*, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Centra intends to apply this exemption.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

In September 2010, the AcSB implemented changes to Part I of the CICA Handbook – *Accounting*; allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of Part I IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Centra meets the AcSB criteria for deferral and intends to adopt Part I IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On April 25, 2013, the IASB issued the Exposure Draft, "Regulatory Deferral Accounts". The Exposure Draft proposes an interim standard intended to allow entities that are first–time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. Under the proposed interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. Comments on the Exposure Draft are due in September of 2013 and the IASB is not expected to make a decision on the proposed interim standard until December of 2013.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in changes to existing IFRS prior to the commencement of Centra's 2015-16 fiscal year. Centra continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

NOTE 3 RELATED PARTY TRANSACTIONS

Centra has related party transactions with its parent which are recorded at the exchange amount. The following transactions are in addition to those disclosed elsewhere in the financial statements:

	2013	2012
	millions of dollars	
Expense		
Net operating and administrative costs	**64**	62
Interest on advances from parent	**18**	19

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 4 FINANCE EXPENSE

	2013	2012
	millions of dollars	
Interest on debt	**21**	22
Interest capitalized	**(3)**	(3)
	18	19

Included in interest on debt is $3 million (2012 - $3 million) in respect of the Provincial Debt Guarantee Fee. The fee during the year was 1.0% of the total outstanding debt guaranteed by the Province of Manitoba (2012 – 1.0%).

NOTE 5 CORPORATE ALLOCATION

Financing costs related to the acquisition of Centra are allocated between gas and electricity operations in accordance with the synergies and benefits derived by each segment of the business at the time of acquisition.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

	2013			2012		
	In service	Accumulated depreciation	Construction in progress	In service	Accumulated depreciation	Construction in progress
	millions of dollars			*millions of dollars*		
Distribution	**648**	**223**	**2**	623	215	2
General plant	**13**	**9**	**-**	14	9	-
	661	**232**	**2**	637	224	2

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 7 REGULATED ASSETS

	2013	2012
	millions of dollars	
Power Smart programs	**46**	44
Deferred taxes	**29**	30
Site restoration costs	**2**	2
Regulatory costs	**1**	1
	78	77

If Centra was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and the net income for 2013 would have decreased by $1 million (2012 – net loss increased by $2 million).

In total, regulated assets of $11 million (2012 - $10 million) were amortized to operations during the period.

NOTE 8 INTANGIBLE ASSETS

	2013			2012		
	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
		millions of dollars			*millions of dollars*	
Computer application development	**8**	**4**	**4**	7	3	4
Land easements	**5**	**1**	**4**	5	1	4
	13	**5**	**8**	12	4	8

The additions to intangible assets for the year were $1 million (2012 - $1 million). In total, intangible assets of $1 million (2012 - $2 million) were amortized to operations during the period.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 9 LONG-TERM DEBT

	2013	2012
	millions of dollars	
Long-term advances from parent	**295**	298
Less: Current portion of long-term debt	**-**	(63)
	295	235

Debt principal amounts and related yields are summarized by fiscal years in which advances are required to be repaid in the following table:

	2013		2012
	Total principal amount of repayment	Weighted average yield rate	Total principal amount of repayment
	millions of dollars		*millions of dollars*
2015	**35**	**1.74%**	35
2019-2023	**20**	**3.18%**	-
2024-2028	**-**	**-**	-
2029-2033	**60**	**5.57%**	30
2034-2038	**130**	**4.40%**	110
2039-2043	**50**	**4.43%**	60
	295	**4.56%**	235

NOTE 10 DUE TO PARENT

Centra's short-term funding is provided by Manitoba Hydro with interest calculated at the three-month T-Bill rate plus a 1% Provincial Guarantee Fee on the outstanding balance. The effective rate for fiscal year 2013 was 0.95% (2012 – 0.90%). There are no fixed repayment terms.

NOTE 11 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2013	2012
	millions of dollars	
Accounts payable and accrued liabilities	**52**	40
Regulated liabilities		
Purchased gas variance accounts	**24**	30
	76	70

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Centra passes costs related to the purchase and transportation of natural gas onto its customers without markup. If Centra was not subject to rate regulation, the purchased gas variance accounts would not be maintained and the actual cost of gas would be expensed in the period incurred. For fiscal year 2013, if actual gas costs were expensed and sales rates were not adjusted accordingly, net income would have decreased by $6 million (2012 - net loss decreased by $17 million).

NOTE 12 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of Centra's non-derivative financial instruments at March 31 were as follows:

	2013		2012	
Financial instruments	Carrying value	Fair value	Carrying value	Fair value
	millions of dollars			
Loans and Receivables				
Accounts receivable and accrued revenue	**76**	**76**	47	47
Other Financial Liabilities				
Long-term debt	**295**	**337**	298	330
Accounts payable and accrued liabilities	**76**	**76**	70	70
Due to parent	**26**	**26**	14	14

The fair value measurement of financial instruments is classified in accordance with a hierarchy of three levels, based on the type of inputs used in making these measurements:

- Level 1 - Quoted prices in active markets for identical assets and liabilities;
- Level 2 - Inputs other than quoted prices that are observable in active markets for the asset or liability; and
- Level 3 - Inputs for the asset or liability that are not based on observable market data.

Financial instrument measurements are Level 1 measurements with the exception of long-term debt which is a Level 2 measurement. Fair value measurement of Centra's long-term debt is based on market yields at close of business on the balance sheet date for similar instruments available in capital markets. The carrying values of all other financial assets and liabilities approximate fair value.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Financial Risks

During the normal course of business, Centra is exposed to a number of financial risks including credit and liquidity risks, and market risk resulting from fluctuations in interest rates and commodity prices. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by Centra, to set risk tolerance limits, establish controls and to monitor risk and adherence to policies. An integrated risk management plan has been developed, and reviewed by the Audit Committee of the Centra Gas Board, to ensure the adequacy of the risk management framework in relation to the risks faced by Centra. The nature of the financial risks and Centra's strategy for managing these risks has not changed significantly from the prior year.

a) Credit Risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Exposure to credit risk related to accounts receivable arising from natural gas sales is minimized due to a large and diversified customer base.

The value of Centra's aged accounts receivable for customers and related bad debt provisions are presented in the following table:

	2013	2012
	millions of dollars	
Under 30 days	**71**	42
30 to 60 days	**4**	3
Over 60 days	**3**	4
	78	49
Provision at end of period	**(2)**	(2)
Total accounts receivable	**76**	47

The provision for bad and doubtful accounts is reviewed annually, based on an estimate of aged receivables that are considered uncollectible. There was no significant change to the allowance for doubtful accounts from last year.

To mitigate credit risk related to the use of derivative instruments, Centra adheres to well established credit exposure limits with institutions that possess a minimum credit rating of 'A' from recognized bond rating agencies or provide a parental guarantee from an 'A' rated parent company. The maximum exposure to credit risk related to Centra's derivative counterparties is equal to the positive fair value of its financial derivatives.

b) Liquidity Risk

Liquidity risk refers to the risk that Centra will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, Centra uses cash generated from operations, as well as short-term funding and long-term advances from Manitoba Hydro.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

The following is an analysis of the contractual undiscounted cash flows payable under financial liabilities and derivative liabilities as at the balance sheet date:

	Carrying Value	2014	2015	2016	2017	2018	2019 and thereafter
			millions of dollars				
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	76	76	-	-	-	-	-
Due to parent	26	26	-	-	-	-	-
Long-term debt*	295	13	48	12	12	12	458
Derivative financial liabilities							
Fixed price swap contracts	-	-	-	-	-	-	-
		115	48	12	12	12	458

*including current portion and interest payments

c) **Market Risk**
Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Centra is exposed to interest rate risk and commodity price risk associated with the price of natural gas.

i. Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. Centra is exposed to interest rate risk associated with amounts due to the parent company, floating rate long-term debt, fixed rate long-term debt maturing within 12 months, and the purchased gas variance accounts, offset by the change in interest capitalization. At March 31, 2013, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $1 million (2012 - $1 million).

ii. Commodity Price Risk
Centra is exposed to natural gas price risk through its purchase of gas for delivery to customers throughout Manitoba. Centra mitigates commodity price risk for its fixed rate service with the use of natural gas price swaps. Centra does not use derivative contracts for trading or speculative purposes.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Centra has entered into natural gas price swaps until July 2016 to purchase 231 510 gigajoules of natural gas at a weighted average fixed price of $5.12/GJ. The weighted average forward price of the swaps per AECO at March 31, 2013 was $3.67/GJ. These contracts are reported as derivatives and carried at fair value on the balance sheet.

The unrealized fair value losses of these natural gas derivative contracts as at March 31 are as follows:

	2013	2012
	millions of dollars	
Fixed price swap contracts	-	(1)

Fair value is calculated by using the monthly forward AECO price as reported by the Natural Gas Exchange as at March 31, 2013.

NOTE 13 COMMITMENTS AND CONTINGENCIES

Centra has energy purchase commitments of $136 million (2012 – $39 million) that relate to future purchases of natural gas (including transportation and storage contracts), which expire in 2020.

Centra has various legal and operational matters pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have a material effect on Centra's financial position or results of operations.

NOTE 14 SHARE CAPITAL

	2013	2012
	millions of dollars	
Share capital		
Authorized		
Unlimited number of common shares		
Issued		
1 505 common shares	**121**	121
	121	121

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 15 CAPITAL MANAGEMENT

Centra manages its capital structure to ensure sufficient retained earnings to enable it to absorb the financial effects of adverse circumstances. Centra's capital requirements are met through cash generated from operations as well as short-term funding and long-term advances from its parent company, the Manitoba Hydro-Electric Board.

NOTE 16 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2012 have been reclassified in order to conform to the presentation adopted in 2013.

Financial Statements

Wuskwatim Power Limited Partnership

March 31, 2013

ERNST & YOUNG

INDEPENDENT AUDITORS' REPORT

To the Partners of
Wuskwatim Power Limited Partnership

We have audited the accompanying financial statements of **Wuskwatim Power Limited Partnership**, which comprise the balance sheet as at March 31, 2013, and the statements of loss, partners' capital and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Wuskwatim Power Limited Partnership** as at March 31, 2013, and the results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Winnipeg, Canada,
July 25, 2013.

Chartered Accountants

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF LOSS
For the year ended March 31, 2013

	Notes	2013	2012
		millions of dollars	
Revenue		**25**	-
Expenses			
Operating and administrative		**5**	-
Finance expense	3	**41**	-
Depreciation		**12**	-
Amortization		**4**	-
Water rentals	4	**3**	-
		65	-
Net Loss		**(40)**	-

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
BALANCE SHEET
As at March 31, 2013

	Notes	2013	2012
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	5	**1 325**	-
Less accumulated depreciation	5	**12**	-
		1 313	-
Construction in progress	5	**1**	1 259
		1 314	1 259
Intangible Assets			
In service	6	**303**	-
Less accumulated amortization	6	**4**	-
		299	-
Work in progress	6	**-**	296
		299	296
Current Assets			
Term investment	7	**1**	1
Accounts receivable	8	**4**	-
Prepaids	9	**4**	2
		9	3
		1 622	1 558
Liabilities and Equity			
Current Liabilities			
Accounts payable		**31**	37
Interest payable	10	**16**	17
		47	54
Long-Term Debt	11	**1 288**	1 201
Total Liabilities		**1 335**	1 255
Partners' Capital	12	**287**	303
		1 622	1 558

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Ken R. F. Adams, P.Eng.
Chair of the general partner of WPLP
(5022649 Manitoba Ltd.)

Darren B. Rainkie, CA
Treasurer and Chair of the Audit Committee

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF PARTNERS' CAPITAL
For the year ended March 31, 2013

	March 31 2012	Contributions	Net Loss	**March 31 2013**
		millions of dollars		
General Partner (5022649 Manitoba Ltd.)	-	-	-	**-**
Manitoba Hydro	203	16	(27)	**192**
Taskinigahp Power Corporation	100	8	(13)	**95**
	303	24	(40)	**287**

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF CASH FLOWS
For the year ended March 31, 2013

	2013	2012
	millions of dollars	
Operating Activities		
Cash receipts from customers	**20**	-
Cash paid to suppliers	**(30)**	-
Interest paid	**(41)**	-
Cash used for operating activities	**(51)**	-
Financing Activities		
Proceeds from issue of units of WPLP	**24**	39
Proceeds from long-term debt	**87**	143
Cash provided by financing activities	**111**	182
Investing Activities		
Additions to property, plant and equipment	**(56)**	(156)
Additions to intangible assets	**(4)**	(27)
Term investment	**-**	1
Cash used for investing activities	**(60)**	(182)
Net increase in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**-**	-

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Wuskwatim Power Limited Partnership (WPLP or the Partnership) was formed on December 9, 2004 under the laws of Manitoba to carry on the business of developing, owning and operating the Wuskwatim hydroelectric generating station (the Project) and related works excluding the transmission facilities but including all dams, dikes, channels, excavations and roads to be located at Taskinigup Falls near Wuskwatim Lake.

An agreement was reached between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) on the development of the Project pursuant to a Project Development Agreement (the PDA) and the execution of the PDA was carried out on June 26, 2006. Initial Closing, as defined under the PDA, occurred on June 28 and 29, 2006. The parties to the PDA executed as a supplementary agreement to the PDA the Wuskwatim Project Development Supplementary Agreement on March 15, 2011. Manitoba Hydro and Taskinigahp Power Corporation (TPC) (owned beneficially by NCN) are limited partners of WPLP. The General Partner, which is a wholly owned subsidiary of Manitoba Hydro, also owns a nominal interest in WPLP. TPC became a limited partner on June 28, 2006.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation

These financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook - Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) Revenue

Manitoba Hydro purchases all the power from the Partnership under a Power Purchase Agreement. Revenue is billed when energy is generated and billed on a monthly basis.

c) Property, Plant and Equipment

Property, plant and equipment is stated at cost and interest applied at WPLP's average cost of debt. Finance expense is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, finance expense allocated to construction will cease, and depreciation and finance expense charged to operations will commence.

Depreciation is provided using the straight-line method over the following years to depreciate the assets over their estimated useful lives:

Generating station	20-125	years
Staff house	20-65	years

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

d) Intangible Assets

Intangible assets include contributions made to Manitoba Hydro for transmission lines. Intangible assets are recorded at cost and interest applied at WPLP's average cost of debt associated with the Interconnection Credit Facility. Once the associated transmission asset is in-service, finance expense allocated to the intangible asset will cease, and amortization and finance expense charged to operations will commence.

Amortization is provided using the straight-line method over the following years to amortize the assets over their estimated useful lives:

Transmission line	10-85	years

e) Use of Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect amounts reported in the financial statements. Actual results may differ from those estimates, but differences are not expected to be material.

NOTE 3 FINANCE EXPENSE

	2013	2012
	millions of dollars	
Interest on debt	**66**	-
Interest capitalized	**(25)**	-
	41	-

Included in interest on debt is the Provincial Debt Guarantee Fee of 1.0% on the Non-Revolving Credit Facility, the Revolving Credit Facility and the Interconnection Credit Facility.

NOTE 4 WATER RENTALS

Water rentals are paid to the Province of Manitoba for the use of water resources in the operation of the Partnership's hydro-electric generating stations.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

	2013			2012		
	In service	**Accumulated depreciation**	**Construction in progress**	In service	Accumulated depreciation	Construction in progress
			millions of dollars			
Generating station	**1 325**	**12**	**-**	-	-	1 259
Staff house	**-**	**-**	**1**	-	-	-
	1 325	**12**	**1**	-	-	1 259

On June 22, 2012, the first generator was put into service. This resulted in $354 million in transfers from construction in progress to property, plant and equipment. On August 22, 2012, the second generator was put into service. This resulted in an additional $520 million in transfers from construction in progress to property, plant and equipment. On October 6, 2012, the last generator was put into service. This resulted in an additional $439 million in transfers from construction in progress to property, plant and equipment. For the year ended March 31, 2013, $19 million (2012 - $46 million) in interest charges have been allocated to the generating station.

Manitoba Hydro is building the staff house in accordance with the Construction Agreement. Depreciation on the staff house will commence when it is in service (December 2014) and will be calculated on a straight-line remaining life basis.

NOTE 6 INTANGIBLE ASSETS

	2013			2012		
	In service	**Accumulated amortization**	**Work in progress**	In service	Accumulated amortization	Work in progress
			millions of dollars			
Transmission line	**303**	**4**	**-**	-	-	296

The intangible asset was moved from work in progress to in-service proportionate to the in-service of the three generating units.

The intangible asset represents amounts accrued or paid to Manitoba Hydro to develop the transmission facilities required to connect the Wuskwatim generating station to Manitoba Hydro's transmission system as specified in the Interconnection and Operating Agreement (IOA). Ownership of these facilities remain with Manitoba Hydro. For the year ended March 31, 2013, $6 million (2012 - $15 million) in interest charges have been allocated to this asset.

Contributions were made by WPLP to Manitoba Hydro according to a schedule included in the IOA. As at March 31, 2013, the excess of scheduled contributions over actual expenditures was recorded as a prepaid asset.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 7 TERM INVESTMENT

This balance represents an investment of $1 million (2012 - $1 million) in surplus cash plus accrued interest that Manitoba Hydro has invested on behalf of the Partnership. This investment is redeemable within two business days on demand and interest earned is based on the average interest rate earned by Manitoba Hydro on its trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment. The effective interest rate as at March 31, 2013 was 1.0% (2012 - 0.9%).

NOTE 8 ACCOUNTS RECEIVABLE

Accounts receivable consist of revenue receivable from Manitoba Hydro and amounts recoverable from the federal government for Goods and Services Tax (GST) paid both of which will be settled in approximately the following month.

NOTE 9 PREPAIDS

This balance represents the excess of scheduled contributions over actual expenditures of $4 million (2012 - $2 million) by WPLP to Manitoba Hydro for the construction of the transmission facilities. Contributions for the transmission facilities are based on the IOA, which differs from actual expenditures.

NOTE 10 INTEREST PAYABLE

Interest payable represents interest owing on the credit facilities and is comprised of the following:

	2013	2012
	millions of dollars	
Non-Revolving Credit Facility	**12**	12
Interconnection Credit Facility	**4**	5
	16	17

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 11 LONG-TERM DEBT

Manitoba Hydro will provide all debt financing for the Project through credit facilities to WPLP. The debt incurred by WPLP through these credit facilities matures 50 years after the in-service date of the first generator in the Project and bears interest at rates specified in the Project Financing Agreement. This debt is secured by the assets owned beneficially by WPLP up to a maximum of $1.3 billion as per the Demand Debenture executed on June 28, 2006 by the General Partner.

Long-term debt is comprised of the following:

	2013	2012
	millions of dollars	
Non-Revolving Credit Facility	**971**	897
Revolving Credit Facility	**13**	12
Interconnection Credit Facility	**304**	292
	1 288	1 201

The Non-Revolving and Revolving Credit Facilities consist of Manitoba Hydro advances received by WPLP to fund a portion of the total capital cost related to the Wuskwatim generating station. Non-revolving advances are limited to an amount that cannot exceed 75% of the total capital cost less any advances received through revolving advances, except for the first ten years following the final closing date when the amount may increase to 85% of the total capital cost less any advances made under the Revolving Credit Facility. The interest rates on the Non-Revolving and Revolving Credit Facility advances are based on Manitoba Hydro's short-term borrowing cost or the one-month Bankers' Acceptance rate plus a 1% Provincial Guarantee Fee which was equal to 2.2% as at March 31, 2013 (2012 – 2.2%). The effective interest rate for the year was 5.2% (2012 – 5.4 %) for the Non-Revolving Credit Facility and 2.1% (2012 – 2.0%) for the Revolving Credit Facility.

Once the principal amount of the advances under the Non-Revolving Credit Facility exceed $200 million, the interest rate is converted to a fixed rate equal to the Canadian Thirty Year Rate, which includes a 1% Provincial Guarantee Fee, in effect on the conversion date. The first conversion date was February 13, 2008, at which time the Canadian Thirty Year Rate was 5.9%. The second conversion date was July 14, 2009, at which time the Canadian Thirty Year Rate was 5.9%. The third conversion date was June 11, 2010, at which time the Canadian Thirty Year Rate was 5.7%. The fourth conversion date was May 13, 2011, at which time the Canadian Thirty Year Rate was 5.4%.

The Interconnection Credit Facility consists of Manitoba Hydro advances received by the Partnership to fund the total capital cost to construct and install transmission facilities and interconnection system upgrades pursuant to the IOA with Manitoba Hydro. The interest rate on the Consolidated Interconnection Credit Facility is a fixed rate based on the weighted average of all Canadian Thirty Year Rates established for the Interconnection Credit Facility on June 29, 2012 and includes a 1.0% Provincial Guarantee Fee. The effective interest rate for the Interconnection Credit Facility for the year was 5.5% (2012 – 5.4%).

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Principal payments on these loans are as follows:

	Total
	millions of dollars
2014	-
2015	-
2016	-
2017	-
2018	-
2019-2063	**1 288**
	1 288

NOTE 12 PARTNERS' CAPITAL

Authorized: Unlimited number of limited partnership units at $1 000 each.
Issued: 326 750.000 limited partnership units at $1 000 each.

As at March 31, limited partnership units issued were as follows:

	2013	2012
	units	
General Partner (5022649 Manitoba Ltd.)	**32.675**	30.283
Manitoba Hydro	**218 889.825**	202 868.050
Taskinigahp Power Corporation	**107 827.500**	99 935.000
	326 750.000	302 833.333

During the year ended March 31, 2013, WPLP issued 23 916.667 limited partnership units. These units have no preference, exchange, pre-emptive or redemption rights.

NOTE 13 FINANCIAL RISKS

Credit Risk
Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. The Partnership's financial asset that is exposed to credit risk is accounts receivable. This risk is minimal as it mainly relates to accounts receivable arising from the sale of power to Manitoba Hydro.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. The Partnership is exposed to interest rate risk associated with debt financing provided by Manitoba Hydro through variable-rate credit facilities.

Liquidity Risk
Liquidity risk refers to the risk that the Partnership will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, the Partnership uses cash generated from operations and credit facilities provided by Manitoba Hydro (Note 11).

NOTE 14 RELATED PARTY TRANSACTIONS

WPLP separately identifies within its records all transactions with Manitoba Hydro at the exchange amount as determined by various agreements. As at March 31, the following balances and transactions relate to Manitoba Hydro:

	2013	2012
	millions of dollars	
Revenue	**25**	-
Expenses		
Operating and administrative	**5**	-
Finance expense (Note 3)	**41**	-
Water rentals (Note 4)	**3**	-
Term Investment (Note 7)	**1**	1
Accounts receivable (Note 8)	**4**	-
Accounts payable	**31**	37
Interest payable (Note 10)	**16**	17
Long-term debt (Note 11)	**1 288**	1 201

Amounts paid to Manitoba Hydro include $87 million (2012 - $156 million) relating to the generating station, $14 million (2012 - $27 million) related to the transmission line, and $4 million (2012 - $7 million) in GST that was recovered from the Canada Revenue Agency with the exception of the accounts receivable noted above. Amounts received from Manitoba Hydro includes $16 million (2012 - $26 million) in equity contributions from both Manitoba Hydro and its wholly owned subsidiary, the General Partner.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

WPLP has also entered into various agreements with Manitoba Hydro to provide services to the Partnership as follows:

a) the Construction Agreement, whereby Manitoba Hydro will construct the Wuskwatim generating station and related works;

b) the Project Financing Agreement, whereby Manitoba Hydro will provide debt financing to WPLP;

c) the Management Agreement, whereby Manitoba Hydro will provide administrative and management functions to WPLP;

d) the Maintenance and Operations Agreement, whereby Manitoba Hydro will provide all maintenance and on-site operations for the Wuskwatim generating station;

e) the IOA, whereby Manitoba Hydro will connect the Wuskwatim generating station to Manitoba Hydro's integrated power system;

f) the Systems Operation and Dispatch Agreement, whereby Manitoba Hydro will operate and dispatch the Wuskwatim generating station in an integrated fashion with Manitoba Hydro's integrated power system; and

g) the Power Purchase Agreement, whereby Manitoba Hydro will purchase from WPLP all of the power generated by the Wuskwatim generating station. WPLP is economically dependent on Manitoba Hydro as the sole purchaser of the power from Wuskwatim.

Amounts paid to Manitoba Hydro under the Management Agreement for the year ended March 31, 2013 totaled $3 million (2012 - $3 million).

NOTE 15 CAPITAL MANAGEMENT

Under the terms of the Wuskwatim PDA, WPLP maintains a 75:25 debt/equity ratio except for the first ten years following the final closing date when the amount may increase to 85% of the total capital cost less any advances made under the Revolving Credit Facility. Long-term debt financing is provided by Manitoba Hydro on an as-required basis. Manitoba Hydro also provides a $50 million revolving credit facility and a separate credit facility to finance the contributions to Manitoba Hydro for the construction of the transmission interconnection facilities necessary to connect the Wuskwatim generating station to the Manitoba Hydro system. The outstanding balance of this Interconnection Credit Facility is excluded from the calculation of the debt/equity ratio.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

WPLP's debt ratio as at March 31 was as follows:

	2013	2012
	millions of dollars	
Long-term debt	**984**	909
Less: Cash and cash equivalents and term investment	**(1)**	(1)
Net debt	**983**	908
Partners' Capital	**287**	303
Debt ratio	**77%**	75%

Financial Statements

Manitoba Hydro International Ltd.

March 31, 2013

ERNST & YOUNG

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Manitoba Hydro International Ltd.

We have audited the accompanying consolidated financial statements of **Manitoba Hydro International Ltd.**, which comprise the consolidated balance sheet as at March 31, 2013, and the consolidated statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Manitoba Hydro International Ltd.** as at March 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Winnipeg, Canada,
June 26, 2013.

Chartered Accountants

MANITOBA HYDRO INTERNATIONAL LTD.

CONSOLIDATED STATEMENT OF INCOME

For the year ended March 31

	Notes	**2013**	2012
		thousands of dollars	
Revenues		**43 170**	31 822
Cost of Operations			
Staff		**14 272**	11 332
Other direct costs	2	**13 762**	8 125
		28 034	19 457
Operating Profit		**15 136**	12 365
Expenses			
Operating and administrative		**9 000**	7 635
Depreciation		**975**	627
Capital and other taxes		**239**	237
		10 214	8 499
Income before other items		**4 922**	3 866
Other Items			
Interest income		**47**	7
Interest expense		**(13)**	-
		34	7
Net Income		**4 956**	3 873

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2013	2012
	thousands of dollars	
Retained earnings, beginning of year	**19 508**	15 635
Net income	**4 956**	3 873
Retained earnings, end of year	**24 464**	19 508

The accompanying notes are an integral part of the consolidated financial statements.

MANITOBA HYDRO INTERNATIONAL LTD.
CONSOLIDATED BALANCE SHEET
As at March 31

	Notes	2013	2012
		thousands of dollars	
Assets			
Property, Plant and Equipment			
In service	4	**8 846**	7 259
Less accumulated depreciation	4	**1 678**	904
		7 168	6 355
Current Assets			
Cash	6	**4 090**	6 209
Cash - restricted	6	**4 460**	1 674
Accounts receivable and accrued revenue	7	**15 644**	10 131
Prepaid expenses		**3 855**	524
		28 049	18 538
Other Assets			
Intangible assets	5	**654**	641
		35 871	25 534
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts payable	7	**5 122**	2 580
Deferred revenue	9	**3 857**	967
		8 979	3 547
Long-Term Deferred Revenue	9	**1 267**	1 318
Shareholder's Equity			
Share capital	11	**1 161**	1 161
Retained earnings		**24 464**	19 508
		25 625	20 669
		35 871	25 534

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MANITOBA HYDRO INTERNATIONAL LTD.
CONSOLIDATED STATEMENT OF CASH FLOWS
For the year ended March 31

	2013	2012
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**40 496**	32 950
Cash paid to suppliers and employees	**(38 061)**	(27 092)
Interest received	**47**	7
Interest paid	**(13)**	-
Cash provided by operating activities	**2 469**	5 865
Investing Activities		
Additions to property, plant and equipment	**(1 587)**	(1 460)
Additions to intangible assets	**(215)**	(442)
Cash used for investing activities	**(1 802)**	(1 902)
Net increase in cash	**667**	3 963
Cash, beginning of year	**7 883**	3 920
Cash, end of year	**8 550**	7 883

The accompanying notes are an integral part of the consolidated financial statements.

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Manitoba Hydro International Ltd. (MHI), a wholly owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro), was incorporated in September 1998 and commenced operations April 1, 1999. As a wholly owned subsidiary of Manitoba Hydro, MHI is not subject to income taxes under Section 149(d) of the Income Tax Act (Canada), however MHI's foreign operations may be subject to income taxes in those jurisdictions.

MHI currently has four business segments, International Utility Services, Manitoba HVDC Research Centre, W.I.R.E. Services and Telecom Services. International Utility Services provides professional consulting, training and electricity infrastructure management services primarily to developing markets. The Manitoba HVDC Research Centre provides technology products, research and development and engineering services to the electrical power system industry. W.I.R.E. Services provides aerial LiDAR data collection and analysis to determine transmission line thermal ratings. Telecom Services provides state of the art broadband telecommunication solutions for telecom carriers, internet service providers and large commercial customers.

The consolidated financial statements include the accounts of MHI and its Nigerian and United Arab Emirates subsidiaries. For purposes of consolidation, all significant intercompany accounts and transactions have been eliminated.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) **Basis of Presentation**

These consolidated financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook – Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) **Property, Plant and Equipment**

Property, plant and equipment are recorded at cost. Depreciation is provided using the straight-line method over the following years to depreciate the assets over their estimated useful lives:

Leasehold improvements	20 years
Furniture and fixtures	20 years
Office, research, computer and telecom equipment	5 years

c) **Intangible Assets**

Intangible assets include computer software. They are recorded at cost and are amortized over their useful lives on a straight-line basis. The expected useful life is as follows:

Computer software	5 years

d) **Revenue Recognition**

Revenue is recognized when services are provided or goods are shipped to the customer. Revenue from maintenance and lease contracts is recognized on a straight-line basis over the term of the contract.

The company recognizes revenue from fixed priced contracts under the percentage-of-completion method. The percentage of completion is determined by comparing the costs incurred as at the consolidated balance sheet date to the total estimated costs, which included costs incurred plus anticipated costs for completing a contract.

e) **Foreign Exchange**

Monetary items denominated in foreign currencies are translated into Canadian dollars at rates of exchange prevailing at the consolidated balance sheet date. Revenues and expenses are translated at the rate of exchange prevailing at the date of the transaction. Foreign exchange gains and losses are included in income.

MHI's integrated foreign subsidiaries, located in Nigeria and the United Arab Emirates, are accounted for under the temporal method. Under this method, monetary assets and liabilities are translated at the exchange rate in effect at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at historical rates. Revenues and expenses are translated at average rates for the period. Exchange gains or losses arising from the translation are included in operations.

f) **Research and Development Expenses**

Research expenses are charged to income in the year they are incurred. Development costs are charged to operations in the period of the expenditure unless a development project meets the criteria under GAAP for deferral and amortization.

g) **Other Direct Costs**

Other direct costs include transportation, accommodations, rents, project equipment, logistics, project bad debt expense, and other.

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2013

h) **Use of Estimates**

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements. Actual amounts could differ from those estimates. Key areas of estimation requiring management to make subjective judgements of matters that are inherently uncertain include the estimates for uncollectible accounts, provision for the useful lives of property, plant and equipment and intangibles. Significant changes in assumptions, including those with respect to future business plans and cash flows, could change the recorded amounts by a material amount.

NOTE 3 OPERATING LINE OF CREDIT

Manitoba Hydro provides MHI with a $1 million revolving line of credit to be used to fund its operations. The line of credit is payable on demand and bears interest at the average one-month Bankers' Acceptance rate. The effective rate for the fiscal year 2013 was nil (2012- nil). The amount outstanding on this operating line of credit as at March 31, 2013 is nil (2012 - nil).

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

			2013
	In service	**Accumulated depreciation**	**Net book value**
		thousands of dollars	
Leasehold improvements	**3 561**	**524**	**3 037**
Furniture and fixtures	**704**	**113**	**591**
Office, research, computer and telecom equipment	**4 581**	**1 041**	**3 540**
	8 846	**1 678**	**7 168**

			2012
	In service	Accumulated depreciation	Net book value
		thousands of dollars	
Leasehold improvements	3 540	347	3 193
Furniture and fixtures	688	78	610
Office, research, computer and telecom equipment	3 031	479	2 552
	7 259	904	6 355

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2013

Included in the cost above is $606 thousand (2012 - $587 thousand) of computer equipment costs which have not been amortized as these assets were not placed in use as of year end.

NOTE 5 INTANGIBLE ASSETS

			2013
	In service	**Accumulated amortization**	**Net book value**
		thousands of dollars	
Computer software	**1 067**	**413**	**654**
	1 067	**413**	**654**

			2012
	In service	Accumulated amortization	Net book value
		thousands of dollars	
Computer software	852	211	641
	852	211	641

The additions to intangible assets for the year totaled $215 thousand (2012 - $442 thousand). In total, intangible assets of $202 thousand (2012 - $123 thousand) were amortized to operations during the period.

NOTE 6 CASH

	2013	2012
	thousands of dollars	
Cash - Canadian bank accounts	**3 916**	6 197
Cash - Overseas bank accounts	**174**	12
	4 090	6 209
Cash - Restricted	**4 460**	1 674
	8 550	7 883

Cash in overseas bank accounts includes funds deposited in foreign currencies in countries other than Canada. Restricted cash relates to deposits held for letters of guarantees for customer contracts. Cash balances earn interest at various rates based on monthly average balances. The effective interest rate for 2013 averaged 0.7% (2012 – 0.5%).

NOTE 7 RELATED PARTY TRANSACTIONS

During the normal course of business, MHI provided $5 264 thousand (2012 - $1 965 thousand) in services to Manitoba Hydro. During the year, Manitoba Hydro provided staffing to MHI at a cost recovery of $2 336 thousand (2012 - $1,771 thousand). MHI paid $475 thousand (2012 - $464 thousand) of expenses pertaining to the rental of fibre strands from Manitoba Hydro. MHI paid nil (2012 - nil) interest on its operating line of credit to Manitoba Hydro. Included in accounts payable is $1 505 thousand (2012 - $362 thousand) owing to Manitoba Hydro. Included in accounts receivable is $740 thousand (2012 - $753 thousand) owing from Manitoba Hydro. Related party transactions are recorded at the exchange amount.

NOTE 8 LEASE COMMITMENTS

As at March 31, 2013, future minimum annual lease payments committed under operating leases over the next five years are as follows:

Years 1-2	$554 thousand per year
Years 3-5	$592 thousand per year

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2013

NOTE 9 DEFERRED REVENUE

Deferred revenue pertains to the deferral of revenue from advance payments from customers. The associated revenue is recognized when the services are provided.

	2013	2012
	thousands of dollars	
Short-Term		
Software maintenance contracts	**645**	794
Dark fibre lease payment	**76**	76
Annual fibre lease contracts	**99**	97
Advance payments from international contracts	**3 037**	-
	3 857	967
Long-Term		
Software maintenance contracts	**394**	369
Dark fibre lease payment	**873**	949
	1 267	1 318
Total	**5 124**	2 285

NOTE 10 FINANCIAL RISKS

MHI is exposed to interest rate, foreign exchange, credit and liquidity risks. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by MHI, to set risk tolerance limits, to establish controls and to monitor risk and adherence to policies. The risk management plan is designed to ensure MHI's risks and exposures are in line with MHI's business objectives and risk tolerances. The nature of the financial risks and MHI's strategy for managing these risks has not changed significantly from the prior year.

Interest Rate Risk

Interest rate risk is associated with variable interest rates paid to the parent company, the Manitoba Hydro-Electric Board. The amount due to parent was nil at March 31, 2013 (2012 - nil).

Foreign Exchange Risk

Financial risk to MHI's operations arises from fluctuations in exchange rates and the volatility in these rates. MHI does not use derivative instruments to reduce its exposure to foreign currency risk. While MHI generates sales in a variety of countries, the sales contracts are based in Canadian dollars, U.S. dollars, Saudi Arabia Riyals, or Euros in order to reduce financial risk of foreign exchange.

Credit Risk

Credit risk arises from the potential that a counterparty will fail to perform its obligations. As at March 31, 2013, MHI is exposed to credit risk from customers in geographic areas primarily in Canada, Africa, Saudi Arabia, the United States, and Europe. MHI mitigates credit risk through the establishment of working relationships with customers and government agencies, and diversification to eliminate significant credit risk concentration.

Liquidity Risk

Liquidity risk refers to the risk that MHI will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, MHI uses cash generated from operations and has access to an operating line of credit from Manitoba Hydro. All accounts payable are due within 30 days of year end. See Note 8 for details of other contractual obligations and their maturities.

NOTE 11 SHARE CAPITAL

Unlimited number of common shares authorized and one common share issued. Shares in the capital of MHI cannot be sold, assigned, transferred or otherwise disposed of unless Manitoba Hydro will, after the disposition, continue to own directly or indirectly all of MHI's shares.

NOTE 12 PENSION PLAN

MHI has a defined contribution pension plan for its employees. MHI's contribution and expense for the year amounted to $200 thousand (2012 - $168 thousand) which is included in operating and administrative expenses. MHI does not carry any pension obligation on its financial statements for its defined contribution plan.

Unaudited Financial Statements of

TESHMONT LP HOLDINGS LTD.

March 31, 2013

TESHMONT LP HOLDINGS LTD.
STATEMENT OF INCOME (UNAUDITED)
For the year ended March 31

	2013	2012
	thousands of dollars	
Revenue		
Partnership income	**436**	645
Interest income	**15**	13
	451	658
Expenses	**12**	10
Net Income	**439**	648

STATEMENT OF RETAINED EARNINGS (UNAUDITED)
For the year ended March 31

	Notes	2013	2012
		thousands of dollars	
Retained earnings as previously reported		**5 072**	3 952
Adoption of new accounting standards by Teshmont LP	3	**-**	472
Retained earnings, beginning of year		**5 072**	4 424
Net income as restated	3	**439**	648
Retained earnings, end of year		**5 511**	5 072

TESHMONT LP HOLDINGS LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2013	2012
		thousands of dollars	
Assets			
Current Assets			
Cash		**18**	10
Term investments	4	**2 256**	1 662
		2 274	1 672
Other Assets			
Investment in partnership	5	**3 237**	3 400
		5 511	5 072
Shareholder's Equity			
Share capital		-	-
Retained earnings		**5 511**	5 072
		5 511	5 072
		5 511	5 072

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

TESHMONT LP HOLDINGS LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2013	2012
	thousands of dollars	
Operating Activities		
Proceeds from partnership income	**599**	400
Interest received	**15**	13
Cash paid to suppliers	**(12)**	(10)
Cash provided by operating activities	**602**	403
Investing Activities		
Term investments	**(594)**	(403)
Cash used for investing activities	**(594)**	(403)
Net increase in cash	**8**	-
Cash, beginning of year	**10**	10
Cash, end of year	**18**	10

The accompanying notes are an integral part of the financial statements.

TESHMONT LP HOLDINGS LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Teshmont LP Holdings Ltd. (Teshmont Holdings) was established February 14, 2003 as a holding company of Manitoba Hydro to acquire a 40% ownership of Teshmont Consultants Limited Partnership (Teshmont LP), which carries on a high voltage engineering and consulting practice.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

(b) **Revenue Recognition**

The investment in Teshmont LP is accounted for by the equity method.

(c) **Financial Instruments**

All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities.

Financial Instruments classified as other financial liabilities are measured at amortized cost using the effective method of amortization. Held-for-trading financial instruments are measured at fair value.

(d) **Use of Estimates**

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

TESHMONT LP HOLDINGS LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 3 ADOPTION OF NEW ACCOUNTING STANDARDS BY TESHMONT LP

During the year ended September 30, 2012, Teshmont LP adopted Part II of the CICA Handbook – Accounting Standards for Private Enterprises. Teshmont LP has elected to adopt the exemption available under Section 1500, *First-time Adoption*, to measure its land and buildings at fair value to prepare its opening balance sheet as at October 1, 2010. The impact of this revaluation was to increase Teshmont LP's Partners' Equity by $1 180 thousand at October 1, 2010 and to reduce expenses by $7 thousand for its year ended September 30, 2011.

Teshmont Holdings has accounted for these changes as a $472 thousand increase to opening retained earnings and the investment in the partnership as at April 1, 2011 and as an increase in net income of $3 thousand for the 2011-12 fiscal year.

NOTE 4 TERM INVESTMENTS

Term investments include surplus cash of $2 256 thousand (2012 - $1 662 thousand) Manitoba Hydro has invested on behalf of Teshmont Holdings. The interest earned and paid on this investment will be based on the average interest rate earned by Manitoba Hydro on their trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment.

NOTE 5 INVESTMENT IN PARTNERSHIP

Teshmont Holdings investment in Teshmont LP is accounted for by the equity method where partnership income increases the investment and profit distributions decrease the investment.

	2013	2012
	thousands of dollars	
Opening Investment - restated	**3 400**	2 683
Parternship Income	**436**	645
Gain on Revaluation of Land and Buildings	**-**	472
Distributions Received	**(599)**	(400)
Ending Investment	**3 237**	3 400

TESHMONT LP HOLDINGS LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 6 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2012 have been reclassified in order to conform to the presentation adopted in 2013.

Financial Statements

Minell Pipelines Ltd.

March 31, 2013

ERNST & YOUNG

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Minell Pipelines Ltd.

We have audited the accompanying financial statements of **Minell Pipelines Ltd.**, which comprise the balance sheet as at March 31, 2013, and the statements of income (loss), retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Minell Pipelines Ltd.** as at March 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Winnipeg, Canada,
June 26, 2013.

MINELL PIPELINES LTD.
STATEMENT OF INCOME (LOSS) AND RETAINED EARNINGS
For the year ended March 31

	Notes	2013	2012
		thousands of dollars	
Revenues			
Rental of gas transmission facilities	8	**198**	198
Expenses			
Operating and administrative	8	**48**	18
Finance expense	4	**17**	18
Depreciation and amortization		**39**	39
Capital and other taxes		**130**	122
		234	197
Net Income (Loss)		**(36)**	1
Retained earnings, beginning of year		**129**	128
Retained earnings, end of year		**93**	129

The accompanying notes are an integral part of the financial statements.

MINELL PIPELINES LTD.
BALANCE SHEET
As at March 31

	Notes	2013	2012
		thousands of dollars	
Assets			
Property, Plant and Equipment			
In service	5	**1 833**	1 833
Less accumulated depreciation	5	**863**	823
		970	1 010
Construction in progress	5	**243**	150
		1 213	1 160
Current Assets			
Prepaid expenses		**2**	2
Other Assets			
Regulated assets	6	**320**	340
		1 535	1 502
Liabilities and Shareholder's Equity			
Current Liabilities			
Due to parent	7	**1 117**	1 046
Accounts payable and accrued liabilities		**24**	25
		1 141	1 071
Contributions in Aid of Construction		**16**	17
Shareholder's Equity			
Share capital	10	**285**	285
Retained earnings		**93**	129
		378	414
		1 535	1 502

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MINELL PIPELINES LTD.
STATEMENT OF CASH FLOWS
For the year ended March 31

	2013	2012
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**198**	198
Cash paid to suppliers	**(159)**	(116)
Interest paid	**(17)**	(18)
Cash provided by operating activities	**22**	64
Financing Activities		
Advance from parent company	**71**	1
Cash provided by financing activities	**71**	1
Investing Activities		
Additions to capital assets, net of contributions	**(93)**	(65)
Cash used for investing activities	**(93)**	(65)
Net change in cash	-	-
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	-	-

The accompanying notes are an integral part of the financial statements.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Minell Pipelines Ltd. (Minell) operates a pipeline transmission system extending from Moosomin, Saskatchewan to Russell, Manitoba. This transmission system is approximately 70 kilometers in length and is used solely for the transportation of natural gas on behalf of Centra Gas Manitoba Inc. (Centra). Minell is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board and is regulated by the National Energy Board (NEB).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation - The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Canadian Institute of Chartered Accountants (CICA) Accounting Handbook, "Pre-Changeover Accounting Standards" and include the significant accounting policies described hereafter.

Rate Regulated Accounting - The rental charged for gas transmission facilities is subject to regulation by the NEB. The rate-setting process ensures that rates charged to customers recover all costs incurred in providing service. As permitted under Canadian GAAP, Minell applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Minell applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise be included in the determination of net income in the year that the cost or credit is incurred. Minell refers to such deferred costs or credits as regulated assets (Note 6) or liabilities which are comprised of the following:

- Deferred taxes - As a result of the change in ownership in 1999, Minell became non-taxable and in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.

Minell's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Natural gas transmission systems and buildings and equipment are recorded at cost, which includes interest and overhead amounts capitalized during the construction period. Once the transfer to in-service property, plant and equipment is made, finance expense allocated to construction ceases and depreciation and finance expense charged to operations commences.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

Depreciation is calculated on a straight-line basis at rates varying from 2.0% to 2.5% based on the estimated useful lives of the assets.

b) **Contributions in Aid of Construction**
Contributions in aid of construction are non-refundable contributions from customers in support of specific transmission facilities. These amounts are amortized to income at rates that correspond with the depreciation rates of the related assets.

c) **Revenue**
Revenue for the use of transmission facilities is from a related party and is recognized on a monthly basis.

d) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments classified as other financial liabilities are measured at amortized cost using the effective interest method of amortization.

e) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). As Minell has no items related to OCI, comprehensive income for the year is equivalent to net income.

f) **Use of Estimates**
The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Minell would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Minell include property, plant

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

and equipment, regulatory assets and liabilities and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus *Improvements to IFRS*, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Minell intends to apply this exemption.

In September 2010, the AcSB implemented changes to Part I of the CICA Handbook – *Accounting*; allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of Part I IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Minell meets the AcSB criteria for deferral and intends to adopt Part I IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On April 25, 2013, the IASB issued the Exposure Draft, "Regulatory Deferral Accounts". The Exposure Draft proposes an interim standard intended to allow entities that are first–time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. Under the proposed interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. Comments on the Exposure Draft are due in September of 2013 and the IASB is not expected to make a decision on the proposed interim standard until December of 2013.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in changes to existing IFRS prior to the commencement of Minell's 2015-16 fiscal year. Minell continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 4 FINANCE EXPENSE

	2013	2012
	thousands of dollars	
Interest on amount due to parent	21	20
Interest capitalized	(4)	(2)
	17	18

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

	2013	2012
	thousands of dollars	
In service		
Land, buildings and equipment	94	94
Gas transmission	1 739	1 739
	1 833	1 833
Accumulated depreciation	863	823
	970	1 010
Construction in progress	243	150
	1 213	1 160

NOTE 6 REGULATED ASSETS

	2013	2012
	thousands of dollars	
Deferred taxes	320	340

If Minell was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the year that they were incurred and the net income for 2013 would have increased by $20 thousand (2012 – net income increased by $20 thousand).

In total, regulated assets of $20 thousand (2012 - $20 thousand) were amortized to operations during the year.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 7 DUE TO PARENT

	2013	2012
	thousands of dollars	
Amount due to parent	**1 117**	1 046

The amount due to the parent company bears interest at the three-month T-Bill rate plus a 1% Provincial Guarantee Fee on the outstanding balance and has no fixed terms of repayment. The effective rate for the year was 1.0% (2012 – 0.9%)

NOTE 8 RELATED PARTY TRANSACTIONS

Rental of gas transmission facilities is to Centra, a company under common control.

In addition to related party transactions disclosed elsewhere in the financial statements, operating and administrative expense includes $48 thousand (2012 - $18 thousand) for administrative and other services performed by Centra. Related party transactions are recorded at the exchange amount.

NOTE 9 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of Minell's financial instruments at March 31 are as follows:

	2013		2012	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		thousands of dollars		
Other Financial Liabilities				
Accounts payable and accrued liabilities	**24**	**24**	25	25
Due to parent	**1 117**	**1 117**	1 046	1 046

Minell is exposed to interest rate risk associated with amounts due to the parent company.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 10 SHARE CAPITAL

	2013	2012
	thousands of dollars	
Share capital		
Authorized		
Unlimited number of shares of one class		
Issued		
285 000 shares	**285**	285

NOTE 11 CAPITAL MANAGEMENT

Minell meets its capital requirements through cash provided by operating activities and advances from its parent company, the Manitoba Hydro-Electric Board.

Unaudited Financial Statements of

MANITOBA HYDRO UTILITY SERVICES LIMITED

March 31, 2013

MANITOBA HYDRO UTILITY SERVICES LIMITED
STATEMENT OF INCOME AND RETAINED EARNINGS (UNAUDITED)
For the year ended March 31

	2013	2012
	thousands of dollars	
Revenues		
Manitoba Hydro meter reading	**3 916**	3 940
Line locating	**23**	26
Other contracted services	**3**	3
Manitoba Hydro contracted services	**562**	1 340
Interactive voice response system	**117**	122
	4 621	5 431
Expenses		
Operating and administrative		
Equipment maintenance	**78**	76
Wages and benefits	**3 922**	4 321
Other operating and administrative	**537**	531
	4 537	4 928
Depreciation and amortization	**64**	74
Capital and other taxes	**74**	78
	4 675	5 080
(Loss) Income before other items	**(54)**	351
Other items		
Interest income	**14**	9
	14	9
Net (Loss) Income	**(40)**	360
Retained earnings, beginning of year	**1 761**	1 401
Retained earnings, end of year	**1 721**	1 761

The accompanying notes are an integral part of the financial statements.

MANITOBA HYDRO UTILITY SERVICES LIMITED
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2013	2012
		thousands of dollars	
Assets			
Property, Plant and Equipment			
Cost	3	**1 032**	1 029
Less accumulated amortization	3	**935**	871
		97	158
Current Assets			
Cash		**63**	530
Term investment	6	**1 325**	1 325
Accounts receivable	4	**789**	434
Prepaid expenses		**17**	17
		2 194	2 306
		2 291	2 464
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts payable and accrued liabilities	6 & 9	**570**	703
Shareholder's Equity			
Share capital	7	-	-
Retained earnings		**1 721**	1 761
		1 721	1 761
		2 291	2 464

The accompanying notes are an integral part of the financial statements.

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MANITOBA HYDRO UTILITY SERVICES LIMITED
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2013	2012
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**4 266**	5 454
Cash paid to suppliers and employees	**(4 744)**	(4 921)
Interest received	**14**	9
Cash (used for) provided by operating activities	**(464)**	542
Investing Activities		
Term investment	**-**	(450)
Additions to property, plant and equipment, net of disposals	**(3)**	(15)
Cash used for investing activities	**(3)**	(465)
Net (decrease) increase in cash	**(467)**	77
Cash, beginning of year	**530**	453
Cash, end of year	**63**	530

The accompanying notes are an integral part of the financial statements.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Manitoba Hydro Utility Services Limited (MHUS) is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro) and commenced operations on January 2, 1998. MHUS provides meter reading, interactive voice response systems and contracted services primarily to Manitoba Hydro and Centra Gas Manitoba Inc., a wholly-owned subsidiary of Manitoba Hydro.

As a wholly-owned subsidiary of Manitoba Hydro, MHUS is not subject to income taxes under section 149(d) of the Income Tax Act (Canada).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) **Property, Plant and Equipment**

Property, plant and equipment are recorded at cost. Depreciation is provided using the straight-line method. The following rates are designed to depreciate the assets over their estimated useful lives:

Furniture	10.0%
Office equipment	20.0%
Computer systems	10.0%
Computer hardware	20.0%
Meter reading devices	20.0%
Line locating equipment	20.0%

c) **Revenue**

Revenue is recognized as services are provided. Revenue from related parties is recorded at the exchange amount.

d) **Financial Instruments**

All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities.

Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Held-for-trading financial instruments are measured at fair value.

e) **Employee Future Benefits**

MHUS full time employees are eligible for pension benefits under the Civil Service Superannuation Board (CSSB) defined benefit plan that provides pension benefits based on years of service.

MHUS is considered a matching employer under the Civil Service Superannuation Act (Act). Under the provisions of the Act, MHUS is required to match employee contributions at a prescribed contribution rate into the Civil Service Superannuation Fund (CSSF) pool of assets. MHUS does not carry any pension obligation value on its financial statements.

Pension expenses for MHUS employees are recognized at the time contributions are made to the Civil Service Superannuation Fund (CSSF), which maintains the funds and obligations relating to these employees in its financial records.

Other benefits earned by employees include vacation, banked sick leave and, incentive compensation. Where applicable, the future costs of these benefits are based on management's best estimates.

f) **Use of Estimates**

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 3 PROPERTY, PLANT AND EQUIPMENT

			2013
	Cost	Accumulated Amortization	Net book value
		thousands of dollars	
Furniture	**30**	**21**	**9**
Office equipment	**12**	**12**	**-**
Computer systems	**85**	**85**	**-**
Computer hardware	**183**	**168**	**15**
Line locating equipment	**24**	**24**	**-**
Meter reading devices	**698**	**625**	**73**
	1 032	**935**	**97**

			2012
	Cost	Accumulated Amortization	Net book value
		thousands of dollars	
Furniture	29	19	10
Office equipment	12	12	-
Computer systems	85	85	-
Computer hardware	180	151	29
Line locating equipment	24	24	-
Meter reading devices	699	580	119
	1 029	871	158

NOTE 4 ACCOUNTS RECEIVABLE

	2013	2012
	thousands of dollars	
Manitoba Hydro	**783**	425
Other	**6**	9
	789	434

NOTE 5 LEASE COMMITMENTS

MHUS leases its premises from Manitoba Hydro. The lease requires payments of approximately $12 thousand per year. In addition, MHUS is responsible for payment of property taxes which approximate $2 thousand annually. The lease was renewed in December 2012 and will expire in November 2013 with a one year extension option.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 6 RELATED PARTY TRANSACTIONS

MHUS identifies all financial transactions with Manitoba Hydro separately in its records at the exchange amount. During the year, Manitoba Hydro provided $266 thousand (2012 - $287 thousand) in services to MHUS. Amounts due to Manitoba Hydro in the amount of $36 thousand (2012 - $42 thousand) are included in accounts payable and accrued liabilities. MHUS paid $12 thousand (2012 - $12 thousand) rent to Manitoba Hydro. MHUS provided $4 632 thousand (2012 - $5 437 thousand) in services to Manitoba Hydro. Amounts receivable from Manitoba Hydro in the amount of $751 thousand (2012 - $402 thousand) are included in accounts receivable. MHUS has made a term investment of surplus cash of $1 325 thousand (2012 - $1 325 thousand) which Manitoba Hydro has invested on its behalf. The interest earned and paid on this investment will be based on the average interest rate earned by Manitoba Hydro on their trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment.

NOTE 7 SHARE CAPITAL

An unlimited number of Class A and Class B shares authorized and ten (10) Class A shares issued. Class B shares are redeemable and retractable and are not entitled to dividends.

NOTE 8 FINANCIAL RISKS

Credit Risk
Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. MHUS's financial asset that is exposed to credit risk is accounts receivable. This risk is minimal as it mainly relates to accounts receivable arising from services provided to Manitoba Hydro.

Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in the market interest rates. MHUS is exposed to interest rate risk associated with debt financing provided by Manitoba Hydro through variable-rate credit facilities. As at March 31, 2013 the amount of financing outstanding is nil (2012 - nil).

NOTE 9 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Included in accounts payable and accrued liabilities as at March 31, 2013 are government remittances payable of $19 420 (2012 - $20 729) relating to Manitoba payroll tax and Manitoba Workers' Compensation Board insurance.

Financial Statements of

KEEYASK HYDROPOWER LIMITED PARTNERSHIP

March 31, 2013

ERNST & YOUNG

INDEPENDENT AUDITORS' REPORT

To the Partners of
Keeyask Hydropower Limited Partnership

We have audited the accompanying financial statements of **Keeyask Hydropower Limited Partnership**, which comprise of the balance sheet as at March 31, 2013, and the statement of partners' capital and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Keeyask Hydropower Limited Partnership** as at March 31, 2013, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Winnipeg, Canada,
July 25, 2013.

Chartered Accountants

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
BALANCE SHEET
As at March 31

	Notes	2013	2012
		dollars	
Assets			
Current Assets			
Cash		**10 000**	10 000
		10 000	10 000
Equity			
Partners' capital	3	**10 000**	10 000
		10 000	10 000

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Ken R. F. Adams, P.Eng.
Chair of the general partner of KHLP
(5900345 Manitoba Ltd.)

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
STATEMENT OF PARTNERS' CAPITAL
For the year ended March 31

	Class	**Units as at March 31, 2013**	**Capital as at March 31, 2013**	Units as at March 31, 2012	Capital as at March 31, 2012
			dollars		*dollars*
Manitoba Hydro	M	**7 499**	**8 249**	7 499	8 249
General Partner (5900345 Manitoba Ltd.)	M	**1**	**1**	1	1
Cree Nation Partners Limited Partnership	K	**1 050**	**1 050**	1 050	1 050
	E	**450**	**-**	450	-
FLCN Keeyask Investments Inc.	K	**350**	**350**	350	350
	E	**150**	**-**	150	-
York Factory First Nation Limited Partnership	K	**350**	**350**	350	350
	E	**150**	**-**	150	-
		10 000	**10 000**	10 000	10 000

The accompanying notes are an integral part of the financial statements.

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
STATEMENT OF CASH FLOWS
For the year ended March 31

	2013	2012
	dollars	
Financing Activities		
Proceeds from issue of units of KHLP	-	-
Cash provided by financing activities	-	-
Net increase in cash	-	-
Cash, beginning of year	**10 000**	10 000
Cash, end of year	**10 000**	10 000

The accompanying notes are an integral part of the financial statements.

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

Keeyask Hydropower Limited Partnership (KHLP or the Partnership) was formed on July 30, 2009 under the laws of Manitoba to carry on the business of developing, owning and operating the Keeyask hydroelectric generating station (the Project) and related works excluding the transmission facilities but including the powerhouse and spillway and all dams, dikes, channels, excavations and roads to be located in the vicinity of Gull Rapids, upstream of the point at which the Nelson River flows into Stephens Lake.

An agreement was reached between Manitoba Hydro and Tataskweyak Cree Nation (TCN) and War Lake First Nation (War Lake) operating as Cree Nation Partners (CNP), York Factory First Nation (York Factory) and Fox Lake Cree Nation (Fox Lake) on the development of the Project pursuant to the Joint Keeyask Development Agreement (the JKDA) signed on May 29, 2009.

Manitoba Hydro, Cree Nation Partners Limited Partnership (CNPLP) (owned beneficially by TCN and War Lake through CNP), FLCN Keeyask Investments Inc. (FLCNKII) (owned beneficially by Fox Lake) and York Factory First Nation Limited Partnership (YFFNLP) (owned beneficially by York Factory) are limited partners of KHLP. 5900345 Manitoba Ltd. (the General Partner), which is a wholly owned subsidiary of Manitoba Hydro, also owns a nominal interest in KHLP.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook – Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP").

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2013

NOTE 3 PARTNERS' CAPITAL

					dollars
Authorized	Unlimited number of limited partnership units (Class E, K and M)				
Issued	Manitoba Hydro	7,499	Class M Units	74.99%	8,249
	General Partner	1	Class M Unit	0.01%	1
	CNPLP	1,050	Class K Units	10.50%	1,050
		450	Class E Units	4.50%	-
	FLCNKII	350	Class K Units	3.50%	350
		150	Class E Units	1.50%	-
	YFFNLP	350	Class K Units	3.50%	350
		150	Class E Units	1.50%	-
	Total	10,000	Class M, K and E Units	100.00%	10,000

The units have no preference, exchange, pre-emptive or redemption rights.

Unaudited Financial Statements of

5022649 MANITOBA LTD.

March 31, 2013

5022649 MANITOBA LTD.
STATEMENT OF INCOME AND RETAINED EARNINGS (UNAUDITED)
For the year ended March 31, 2013

	2013	2012
	thousands of dollars	
Partnership Loss	(4)	-
Retained earnings, beginning of year	-	-
Retained earnings, end of year	(4)	-

The accompanying notes are an integral part of the financial statements.

5022649 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2013	2012
		thousands of dollars	
Assets			
Current Assets			
Cash		**4**	7
Other Assets			
Investment in Partnership	3	**29**	30
		33	37
Shareholders' Equity			
Share capital	4	**37**	37
Retained earnings		**(4)**	-
		33	37

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Ken R. F. Adams, P.Eng.
Chair of the general partner of WPLP
(5022649 Manitoba Ltd.)

Darren B. Rainkie, CA
Treasurer and Chair of the
Audit Committee

5022649 MANITOBA LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31, 2013

	2013	2012
	thousands of dollars	
Financing Activities		
Proceeds from common share issue	-	10
Cash provided by financing activities	-	10
Investing Activities		
Investment in partnership	(3)	(4)
Cash used for investing activities	(3)	(4)
Net (decrease) increase in cash	(3)	6
Cash, beginning of year	7	1
Cash, end of year	4	7

The accompanying notes are an integral part of the financial statements.

5022649 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

5022649 Manitoba Ltd. was incorporated on November 30, 2004 and is a wholly owned subsidiary of Manitoba Hydro. This company is the General Partner of the Wuskwatim Power Limited Partnership (Partnership) and has acquired .01% ownership of the Partnership.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Canadian Institute of Chartered Accountants ("CICA") Accounting Handbook - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

(b) **Revenue Recognition**

The investment in the Partnership is accounted for by the equity method.

NOTE 3 INVESTMENT IN PARTNERSHIP

5022649 Manitoba Ltd.'s investment in the Partnership is accounted for using the equity method where contributions to the Partnership increase the investment and the General Partner's share of the Partnership loss decreases the investment.

	2013	2012
	thousands of dollars	
Investment in Partnership, beginning of year	**30**	26
Contributions to Partnership	**3**	4
Partnership loss	**(4)**	-
Investment in Partnership, end of year	**29**	30

NOTE 4 SHARE CAPITAL

An unlimited number of common shares are authorized and 3 700 common shares have been issued.

Unaudited Financial Statements of

5900345 MANITOBA LTD.

March 31, 2013

5900345 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2013	2012
		dollars	
Assets			
Current Assets			
Cash		**1 000**	1 000
Other Assets			
Investment in Keeyask Hydropower Limited Partnership		**1**	1
		1 001	1 001
Shareholder's Equity			
Share Capital	2	**1 001**	1 001
		1 001	1 001

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

~~Ken~~ R. F. Adams, P.Eng.
Chairman of the general partner of KHLP
(5900345 Manitoba Ltd.)

5900345 MANITOBA LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2013	2012
	dollars	
Financing Activities		
Proceeds from common share issue	-	-
Cash (used for) provided by financing activities	-	-
Investing Activities		
Investment in Partnership	-	-
Cash (used for) provided by investing activities	-	-
Net increase in cash	-	-
Cash, beginning of year	**1 000**	1 000
Cash, end of year	**1 000**	1 000

The accompanying notes are an integral part of the financial statements.

5900345 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

5900345 Manitoba Ltd. was incorporated on June 17, 2009 and is a wholly owned subsidiary of Manitoba Hydro. This company is the General Partner of the Keeyask Hydropower Limited Partnership and has acquired .01% ownership of the Partnership.

NOTE 2 SHARE CAPITAL

An unlimited number of common shares authorized and 1001 common shares issued.

Unaudited Financial Statements of

4985371 MANITOBA LTD.

March 31, 2013

4985371 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Note	2013	2012
		dollars	
Assets			
Cash		1	1
		1	1
Shareholder's Equity			
Share Capital	2	1	1
		1	1

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

4985371 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2013

NOTE 1 NATURE OF THE ORGANIZATION

4985371 Manitoba Ltd was established September 14, 2004 to hold legal title of the property at 360 Portage Avenue. As a bare trustee, 4985371 Manitoba Ltd holds title to the property without any further duty to perform, except convey title to the beneficiary, Manitoba Hydro, upon demand.

NOTE 2 SHARE CAPITAL

An unlimited number of Class A common shares authorized and one Class A common share issued.

Financial Statements

Centra Gas Manitoba Inc.

March 31, 2014

Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Centra Gas Manitoba Inc.

We have audited the accompanying financial statements of **Centra Gas Manitoba Inc.**, which comprise the balance sheet as at March 31, 2014 and the statements of income (loss), retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Centra Gas Manitoba Inc.** as at March 31, 2014 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Winnipeg, Canada,
June 25, 2014.

Chartered Accountants

CENTRA GAS MANITOBA INC.

STATEMENT OF INCOME

For the year ended March 31

	Notes	2014	2013
		millions of dollars	
Revenues			
Commodity		**252**	182
Distribution		**161**	146
		413	328
Cost of gas sold		**252**	182
		161	146
Other income		**2**	1
		163	147
Expenses			
Operating and administrative	4	**67**	64
Finance expense	4 & 5	**16**	18
Depreciation and amortization	6	**28**	27
Capital and other taxes		**20**	18
Corporate allocation	7	**12**	12
		143	139
Net Income		**20**	8

The accompanying notes are an integral part of the financial statements.

STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2014	2013
	millions of dollars	
Retained earnings, beginning of year	**42**	34
Net income	**20**	8
Retained earnings, end of year	**62**	42

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
BALANCE SHEET
As at March 31

	Notes	2014	2013
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	8	**684**	661
Less accumulated depreciation	8	**240**	232
		444	429
Construction in progress	8	**4**	2
		448	431
Current Assets			
Accounts receivable and accrued revenue		**109**	76
Gas in storage		**-**	21
		109	97
Other Assets			
Regulated assets	9	**124**	78
Intangible assets	10	**8**	8
		132	86
		689	614
Liabilities and Shareholder's Equity			
Long-Term Debt	11	**270**	295
Current Liabilities			
Due to parent	12	**34**	26
Accounts payable and accrued liabilities		**107**	52
Current portion of long-term debt	11	**35**	-
		176	78
Other Liabilities			
Regulated liabilities	9	**6**	24
Refundable advances from customers		**12**	21
		18	45
Contributions in Aid of Construction		**42**	33
Shareholder's Equity			
Share capital	15	**121**	121
Retained earnings		**62**	42
		183	163
		689	614

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

CENTRA GAS MANITOBA INC.
STATEMENT OF CASH FLOWS
For the year ended March 31

	2014	2013
	millions of dollars	
Operating Activities		
Cash receipts from customers	**318**	294
Cash paid to suppliers	**(271)**	(239)
Interest paid	**(18)**	(20)
Cash provided by operating activities	**29**	35
Financing Activities		
Long-term repayments to parent	**-**	(63)
Long-term advances from parent	**10**	60
Short-term advances from parent	**8**	12
Cash provided by financing activities	**18**	9
Investing Activities		
Property, plant and equipment, net of contributions	**(35)**	(34)
Other	**(12)**	(10)
Cash used for investing activities	**(47)**	(44)
Net change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**-**	-

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Centra Gas Manitoba Inc. (Centra) distributes natural gas to more than 272 000 residential, commercial and industrial customers throughout Manitoba. Centra delivers natural gas to its customers through a network of transmission pipelines and distribution mains totaling approximately 9 800 kilometers in length. Centra is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro) and is regulated by the Public Utilities Board of Manitoba (PUB).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Chartered Professional Accountants (CPA) Canada Handbook - Accounting - Pre-Changeover Accounting Standards and include the significant accounting policies described hereafter.

Rate-Regulated Accounting - The prices charged for the sale of natural gas within Manitoba are subject to review and approval by the Public Utilities Board of Manitoba (PUB). The rate-setting process is designed such that rates charged to natural gas customers recover all costs incurred in providing gas service to customers. As permitted under Canadian GAAP, Centra applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of Canadian GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Centra applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise have been included in the determination of net income in the year that the cost or credit is incurred. Centra refers to such deferred costs or credits as regulated assets or regulated liabilities (Note 9) which are generally comprised of the following:

- Power Smart programs - The costs of Centra's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.
- Deferred taxes - As a result of its acquisition by Manitoba Hydro in 1999, Centra became non-taxable and, in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.
- Site restoration costs - Site restoration costs incurred are deferred and amortized on a straight-line basis over a period of 15 years.
- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. The difference between the recorded cost of natural gas and the actual cost of natural gas is recovered or refunded in future rates.

- Demand side management (DSM) deferral – In Board Order 85/13, the PUB directed that the differences between actual and planned spending on gas DSM for the 2013-14 fiscal year be recorded in a regulatory deferral account. The cumulative difference for 2013-2014 has been recorded as a regulated liability with an offsetting balance recorded as a regulated asset. The disposition of this regulatory deferral will be determined at a future PUB proceeding.

Centra's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Property, plant and equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases and depreciation and interest charged to operations commences.

b) **Depreciation**
Depreciation is provided on a straight-line remaining-life basis. The range of estimated service lives of each major asset category is as follows:

Distribution	5 - 65 years
General plant	10 - 45 years

Provision for removal costs of major property, plant and equipment is charged to depreciation expense on a straight-line basis over the remaining service lives of the related assets. Retirements of these assets, including costs of removal, are charged to accumulated depreciation with no gains or losses reflected in operations. The estimated service lives and removal costs of the assets are based upon depreciation studies conducted periodically by Centra.

c) **Intangible Assets**
Intangible assets include computer application development costs and land easements. Intangible assets are recorded at cost. The cost of computer application development includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Intangible assets with finite useful lives are amortized over their useful lives on a straight-line basis. The expected useful lives are as follows:

Computer application development	10 years
Land easements	75 years

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

The estimated service lives of intangible assets are based upon depreciation studies conducted periodically by Centra.

d) **Contributions in Aid of Construction**
Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

e) **Gas in Storage**
Gas in storage is valued at average cost.

f) **Revenues**
Gas sales are recognized upon delivery to the customer and include an estimate of gas deliveries not yet billed at period-end.

g) **Cost of Gas Sold**
Cost of natural gas sold is recorded at the same rates charged to customers.

h) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities. Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in income in the period in which they arise.

i) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). As Centra has no items related to OCI, comprehensive income for the year is equivalent to net income.

j) **Foreign Currency Translation**
Current monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at the exchange rate prevailing as at the balance sheet date. Gains or losses related to natural gas storage purchases which arise from the date of receipt to date of payment are included as inventoried cost. All other exchange gains and losses on the translation of current monetary assets and liabilities are credited or charged to finance expense in the current period.

k) **Derivatives**
Centra does not engage in derivative trading or speculative activities. Centra mitigates natural gas price volatility to customers through the use of natural gas price swaps. Fixed price swaps are carried at fair value on the balance sheet with gains and losses recorded in income.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

l) **Debt Discounts and Premiums**
Debt discounts and premiums are amortized to finance expense using the effective interest method.

m) **Use of Estimates**
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual amounts could differ from those estimates, but differences are not expected to be material.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Centra would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Centra include property, plant and equipment, regulatory assets and liabilities and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus Improvements to IFRS, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Centra intends to apply this exemption.

In September 2010, the AcSB implemented changes to Part I of the CPA Canada Handbook – International Financial Reporting Standards allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Centra meets the AcSB criteria for the deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On January 30, 2014, the IASB issued the interim standard IFRS 14 *Regulatory Deferral Accounts* for rate-regulated activities effective January 1, 2016 with earlier adoption permitted. Centra will early adopt the interim standard upon transition to IFRS effective

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

April 1, 2015 and will continue to recognize regulatory deferral accounts for its financial reporting.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-Regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in modifications to existing IFRS prior to the commencement of Centra's 2015-16 fiscal year. Centra continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

NOTE 4 RELATED PARTY TRANSACTIONS

Centra has related party transactions with its parent which are recorded at the exchange amount. The following transactions are in addition to those disclosed elsewhere in the financial statements:

	2014	2013
	millions of dollars	
Expense		
Net operating and administrative costs	**67**	64
Interest on advances from parent	**16**	18

NOTE 5 FINANCE EXPENSE

	2014	2013
	millions of dollars	
Interest on debt	**19**	21
Interest capitalized	**(3)**	(3)
	16	18

Included in interest on debt is $3 million (2013 - $3 million) in respect of the Provincial Debt Guarantee Fee. The fee during the year was 1.0% of the total outstanding debt guaranteed by the Province of Manitoba (2013 – 1.0%).

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 6 DEPRECIATION AND AMORTIZATION

	2014	2013
	millions of dollars	
Depreciation of property, plant and equipment	**17**	18
Amortization of regulated assets	**8**	7
Amortization of intangible assets	**3**	2
	28	27

NOTE 7 CORPORATE ALLOCATION

Financing costs related to the acquisition of Centra are allocated between gas and electricity operations in accordance with the synergies and benefits derived by each segment of the business at the time of acquisition.

NOTE 8 PROPERTY, PLANT AND EQUIPMENT

	2014			2013		
	In service	Accumulated depreciation	Construction in progress	In service	Accumulated depreciation	Construction in progress
	millions of dollars			*millions of dollars*		
Distribution	**672**	**232**	**4**	648	223	2
General plant	**12**	**8**	**-**	13	9	-
	684	**240**	**4**	661	232	2

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 9 REGULATED ASSETS AND LIABILITIES

	2014	2013
	millions of dollars	
Regulated assets		
Power Smart programs	**54**	46
Purchased gas variance accounts	**39**	-
Deferred taxes	**27**	29
Site restoration costs	**3**	2
Regulatory costs	**1**	1
	124	78
Regulated liabilities		
DSM deferral	**6**	-
Purchased gas variance accounts	**-**	24
	6	24

If Centra was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and the net income for 2014 would have decreased by $1 million (2013 – net income decreased by $1 million).

In total, regulated assets of $12 million (2013 - $11 million) were amortized to operations during the period.

Centra passes costs related to the purchase and transportation of natural gas onto its customers without markup. If Centra was not subject to rate regulation, the purchased gas variance accounts would not be maintained and the actual cost of gas would be expensed in the period incurred. For fiscal year 2014, if actual gas costs were expensed and sales rates were not adjusted accordingly, net income would have decreased by $63 million (2013 – decreased by $6 million).

NOTE 10 INTANGIBLE ASSETS

	2014			2013		
	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
		millions of dollars			*millions of dollars*	
Computer application development	**8**	**4**	**4**	8	4	4
Land easements	**5**	**1**	**4**	5	1	4
	13	**5**	**8**	13	5	8

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

The additions to intangible assets for the year were $1 million (2013 - $1 million). In total, intangible assets of $1 million (2013 - $1 million) were amortized to operations during the period.

NOTE 11 LONG-TERM DEBT

	2014	2013
	millions of dollars	
Long-term advances from parent	**305**	295
Less: Current portion of long-term debt	**35**	-
	270	295

Debt principal amounts and related yields are summarized by fiscal years in which advances are required to be repaid in the following table:

	2014		2013
	Total principal amount of repayment	Weighted average yield rate	Total principal amount of repayment
	millions of dollars		*millions of dollars*
2015	**35**	**1.62%**	35
2019-2023	**20**	**3.18%**	20
2024-2028	**10**	**3.40%**	-
2029-2033	**60**	**5.57%**	60
2034-2038	**130**	**4.40%**	130
2039-2043	**50**	**4.43%**	50
	305	**4.56%**	295

NOTE 12 DUE TO PARENT

Centra's short-term funding is provided by Manitoba Hydro with interest calculated at the three-month T-Bill rate plus 1% Provincial Guarantee Fee on the outstanding balance. The effective rate for fiscal year 2014 was 0.95% (2013 – 0.95%). There are no fixed repayment terms.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 13 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of Centra's financial instruments at March 31 were as follows:

	2014		2013	
Financial instruments	Carrying value	Fair value	Carrying value	Fair value
	millions of dollars			
Loans and Receivables				
Accounts receivable and accrued revenue	**109**	**109**	76	76
Other Financial Liabilities				
Long-term debt	**305**	**334**	295	337
Accounts payable and accrued liabilities	**107**	**107**	52	52
Due to parent	**34**	**34**	26	26

The fair value measurement of financial instruments is classified in accordance with a hierarchy of three levels, based on the type of inputs used in making these measurements:

Level 1 - Quoted prices in active markets for identical assets and liabilities;
Level 2 - Inputs other than quoted prices that are observable in active markets for the asset or liability; and
Level 3 - Inputs for the asset or liability that are not based on observable market data.

Financial instrument measurements are Level 1 measurements with the exception of long-term debt which is a Level 2 measurement. Fair value measurement of Centra's long-term debt is based on market yields at close of business on the balance sheet date for similar instruments available in capital markets. The carrying values of all other financial assets and liabilities approximate fair value.

Financial Risks
During the normal course of business, Centra is exposed to a number of financial risks including credit and liquidity risks, and market risk resulting from fluctuations in interest rates and commodity prices. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by Centra, to set risk tolerance limits, establish controls and to monitor risk and adherence to policies. An integrated risk management plan has been developed, and reviewed by the Audit Committee of the Centra Gas Board, to ensure the adequacy of the risk management framework in relation to the risks faced by Centra. The nature of the financial risks and Centra's strategy for managing these risks has not changed significantly from the prior year.

a) Credit Risk
Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Exposure to credit risk related to

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

accounts receivable arising from natural gas sales is minimized due to a large and diversified customer base.

The value of Centra's aged accounts receivable for customers and related bad debt provisions are presented in the following table:

	2014	2013
	millions of dollars	
Under 30 days	**103**	71
31 to 60 days	**4**	4
Over 60 days	**4**	3
	111	78
Provision at end of year	**(2)**	(2)
Total accounts receivable	**109**	76

The provision for bad and doubtful accounts is reviewed annually, based on an estimate of aged receivables that are considered uncollectible. There was no significant change to the allowance for doubtful accounts from last year.

To mitigate credit risk related to the use of derivative instruments, Centra adheres to well established credit exposure limits with institutions that possess a minimum credit rating of 'A' from recognized bond rating agencies or provide a parental guarantee from an 'A' rated parent company. The maximum exposure to credit risk related to Centra's derivative counterparties is equal to the positive fair value of its financial derivatives.

b) Liquidity Risk

Liquidity risk refers to the risk that Centra will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, Centra uses cash generated from operations, as well as short-term funding and long-term advances from Manitoba Hydro.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

The following is an analysis of the contractual undiscounted cash flows payable under financial liabilities and derivative liabilities as at the balance sheet date:

	Carrying Value	2015	2016	2017	2018	2019	2020 and thereafter
				millions of dollars			
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	107	107	-	-	-	-	-
Due to parent	34	34	-	-	-	-	-
Long-term debt*	305	48	12	12	12	12	458
Derivative financial liabilities							
Fixed price swap contracts	-	-	-	-	-	-	-
		189	12	12	12	12	458

*including current portion and interest payments

c) Market Risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Centra is exposed to interest rate risk and commodity price risk associated with the price of natural gas.

i. Interest Rate Risk

Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. Centra is exposed to interest rate risk associated with amounts due to the parent company, floating rate long-term debt, fixed rate long-term debt maturing within 12 months, and the purchased gas variance accounts, offset by the change in interest capitalization. At March 31, 2014, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $0.2 million (2013 - $0.7 million).

ii. Commodity Price Risk

Centra is exposed to natural gas price risk through its purchase of gas for delivery to customers throughout Manitoba. Centra mitigates commodity price risk for its fixed rate service with the use of natural gas price swaps. Centra does not use derivative contracts for trading or speculative purposes.

Centra has entered into natural gas price swaps until July 2016 to purchase 87 450 gigajoules (GJ) of natural gas at a weighted average fixed price of $5.15/GJ. The weighted average forward price of the swaps per AECO at March 31, 2014 was $4.37/GJ. These contracts are reported as derivatives and carried at fair value on the balance sheet. The unrealized fair value losses of these natural gas derivative contracts at March 31 are nil (2013 - nil).

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 14 COMMITMENTS AND CONTINGENCIES

Centra has energy purchase commitments of $182 million (2013 – $136 million) that relate to future purchases of natural gas (including transportation and storage contracts), which expire in 2020.

Centra has various legal and operational matters pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have a material effect on Centra's financial position or results of operations.

NOTE 15 SHARE CAPITAL

	2014	2013
	millions of dollars	
Share capital		
Authorized		
Unlimited number of common shares		
Issued		
1 505 common shares	**121**	121
	121	121

NOTE 16 CAPITAL MANAGEMENT

Centra manages its capital structure to ensure sufficient retained earnings to enable it to absorb the financial effects of adverse circumstances. Centra's capital requirements are met through cash generated from operations as well as short-term funding and long-term advances from its parent company, the Manitoba Hydro-Electric Board.

NOTE 17 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2013 have been reclassified in order to conform to the presentation adopted in 2014.

Financial Statements

Wuskwatim Power Limited Partnership

March 31, 2014

EY

Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Partners of
Wuskwatim Power Limited Partnership

We have audited the accompanying financial statements of **Wuskwatim Power Limited Partnership**, which comprise the balance sheet as at March 31, 2014, and the statements of loss, partners' capital and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Wuskwatim Power Limited Partnership** as at March 31, 2014, and the results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Winnipeg, Canada,
July 23, 2014.

Chartered Accountants

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF LOSS
For the year ended March 31

	Notes	2014	2013
		millions of dollars	
Revenue		**47**	25
Expenses			
Operating and administrative		**11**	5
Finance expense	3	**71**	41
Depreciation		**20**	12
Amortization		**7**	4
Water rentals	4	**5**	3
		114	65
Net Loss		**(67)**	(40)

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
BALANCE SHEET
As at March 31

	Notes	2014	2013
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	5	**1 336**	1 325
Less accumulated depreciation	5	**31**	12
		1 305	1 313
Construction in progress	5	**2**	1
		1 307	1 314
Intangible Assets			
In service	6	**305**	303
Less accumulated amortization	6	**11**	4
		294	**299**
Current Assets			
Term investment	7	**3**	1
Accounts receivable	8	**7**	4
Prepaids	9	**-**	4
		10	9
		1 611	1 622
Liabilities and Equity			
Current Liabilities			
Accounts payable		**22**	31
Interest payable	10	**17**	16
		39	47
Long-Term Debt	11	**1 350**	1 288
Total Liabilities		**1 389**	1 335
Partners' Capital	12	**222**	287
		1 611	1 622

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Lorne Midford, P.Eng.
Chair of the general partner of WPLP
(5022649 Manitoba Ltd.)

Darren B. Rainkie, CA
Treasurer and Chair of the Audit Committee

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF PARTNERS' CAPITAL
For the year ended March 31

	March 31 2013	Contributions	Net Loss	**March 31 2014**
		millions of dollars		
General Partner (5022649 Manitoba Ltd.)	-	-	-	-
Manitoba Hydro	192	2	(45)	**149**
Taskinigahp Power Corporation	95	-	(22)	**73**
	287	2	(67)	**222**

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
STATEMENT OF CASH FLOWS
For the year ended March 31

	2014	2013
	millions of dollars	
Operating Activities		
Cash receipts from customers	45	20
Cash paid to suppliers	(16)	(5)
Interest paid	(70)	(25)
Cash used for operating activities	(41)	(10)
Financing Activities		
Proceeds from issue of units of WPLP	2	24
Proceeds from long-term debt	63	87
Cash provided by financing activities	65	111
Investing Activities		
Additions to property, plant and equipment	(22)	(87)
Additions to intangible assets	1	(14)
Term investment	(3)	-
Cash used for investing activities	(24)	(101)
Net increase in cash and cash equivalents	-	-
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	-	-

The accompanying notes are an integral part of the financial statements.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Wuskwatim Power Limited Partnership (WPLP or the Partnership) was formed on December 9, 2004 under the laws of Manitoba to carry on the business of developing, owning and operating the Wuskwatim hydro-electric generating station (the Project) and related works excluding the transmission facilities but including all dams, dikes, channels, excavations and roads to be located at Taskinigup Falls near Wuskwatim Lake.

An agreement was reached between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) on the development of the Project pursuant to a Project Development Agreement (the PDA) and the execution of the PDA was carried out on June 26, 2006. Initial Closing, as defined under the PDA, occurred on June 28 and 29, 2006. The parties to the PDA executed as a supplementary agreement to the PDA the Wuskwatim Project Development Supplementary Agreement on March 15, 2011. Manitoba Hydro and Taskinigahp Power Corporation (TPC) (owned beneficially by NCN) are limited partners of WPLP. The General Partner, which is a wholly owned subsidiary of Manitoba Hydro, also owns a nominal interest in WPLP. TPC became a limited partner on June 28, 2006.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) Basis of Presentation
These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook - Accounting – Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) Revenue
Manitoba Hydro purchases all the power from the Partnership under a Power Purchase Agreement. Revenue is billed when energy is generated and billed on a monthly basis.

c) Property, Plant and Equipment
Property, plant and equipment is stated at cost and interest applied at WPLP's average cost of debt. Finance expense is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, finance expense allocated to construction will cease, and depreciation and finance expense charged to operations will commence.

Depreciation is provided using the straight-line method over the following years to depreciate the assets over their estimated useful lives:

Generating station	20-125	years
Staff house	20-65	years

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

d) Intangible Assets

Intangible assets include contributions made to Manitoba Hydro for transmission lines. Intangible assets are recorded at cost and interest applied at WPLP's average cost of debt associated with the Interconnection Credit Facility. Once the associated transmission asset is in-service, finance expense allocated to the intangible asset will cease, and amortization and finance expense charged to operations will commence.

Amortization is provided using the straight-line method over the following years to amortize the assets over their estimated useful lives:

Transmission line	10-85	years

e) Use of Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect amounts reported in the financial statements. Actual results may differ from those estimates, but differences are not expected to be material.

NOTE 3 FINANCE EXPENSE

	2014	2013
	millions of dollars	
Interest on debt	**71**	66
Interest capitalized	**-**	(25)
	71	41

Included in interest on debt is the Provincial Debt Guarantee Fee of 1.0% on the Non-Revolving Credit Facility, the Revolving Credit Facility and the Interconnection Credit Facility.

NOTE 4 WATER RENTALS

Water rentals are paid to the Province of Manitoba for the use of water resources in the operation of the Partnership's hydro-electric generating stations.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

	2014			2013		
	In service	**Accumulated depreciation**	**Construction in progress**	In service	Accumulated depreciation	Construction in progress
			millions of dollars			
Generating station	**1 336**	**31**	**-**	1 325	12	-
Staff house	**-**	**-**	**2**	-	-	1
	1 336	**31**	**2**	1 325	12	1

For the year ended March 31, 2014, nil (2013 - $19 million) in interest charges have been allocated to the generating station.

Manitoba Hydro is building the staff house in accordance with the Construction Agreement. Depreciation on the staff house will commence when it is in service and will be calculated on a straight-line remaining life basis.

NOTE 6 INTANGIBLE ASSETS

	2014			2013		
	In service	**Accumulated amortization**	**Work in progress**	In service	Accumulated amortization	Work in progress
			millions of dollars			
Transmission line	**305**	**11**	**-**	303	4	-

The intangible asset represents amounts accrued or paid to Manitoba Hydro to develop the transmission facilities required to connect the Wuskwatim generating station to Manitoba Hydro's transmission system as specified in the Interconnection and Operating Agreement (IOA). Ownership of these facilities remain with Manitoba Hydro. For the year ended March 31, 2014, nil (2013 - $6 million) in interest charges have been allocated to this asset.

NOTE 7 TERM INVESTMENT

This balance represents an investment of $3 million (2013 - $1 million) in surplus cash plus accrued interest that Manitoba Hydro has invested on behalf of the Partnership. This investment is redeemable within two business days on demand and interest earned is based on the average interest rate earned by Manitoba Hydro on its trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment. The effective interest rate as at March 31, 2014 was 1.0% (2013 - 1.0%).

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 8 ACCOUNTS RECEIVABLE

Accounts receivable consist of revenue receivable, the balance of the transmission line over contribution from Manitoba Hydro and amounts recoverable from the federal government for Goods and Services Tax (GST) paid. These amounts will be settled in approximately the following month.

NOTE 9 PREPAIDS

This balance represents the excess of scheduled contributions over actual expenditures of nil (2013 - $4 million) by WPLP to Manitoba Hydro for the construction of the transmission facilities. Contributions for the transmission facilities are based on the IOA, which differs from actual expenditures.

NOTE 10 INTEREST PAYABLE

Interest payable represents interest owing on the credit facilities and is comprised of the following:

	2014	2013
	millions of dollars	
Non-Revolving Credit Facility	**13**	12
Interconnection Credit Facility	**4**	4
	17	16

NOTE 11 LONG-TERM DEBT

Manitoba Hydro will provide all debt financing for WPLP through various credit facilities. The debt incurred by WPLP through these credit facilities matures 50 years after the in-service date of the first generator in the Project and bears interest at rates specified in the Project Financing Agreement. This debt is secured by the assets owned beneficially by WPLP up to a maximum of $1.3 billion as per the Demand Debenture executed on June 28, 2006 by the General Partner.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

Long-term debt is comprised of the following:

	2014	2013
	millions of dollars	
Non-Revolving Credit Facility	**1 032**	971
Revolving Credit Facility	**15**	13
Interconnection Credit Facility	**303**	304
	1 350	1 288

The Non-Revolving and Revolving Credit Facilities consist of Manitoba Hydro advances received by WPLP to fund a portion of the total capital cost and on-going operating costs related to the Wuskwatim generating station. Non-revolving advances are limited to an amount that cannot exceed 75% of the total capital cost less any advances received through revolving advances, except for the first ten years following the final closing date when the amount may increase to 85% of the total capital cost less any advances made under the Revolving Credit Facility. The interest rates on the Non-Revolving and Revolving Credit Facility advances are based on Manitoba Hydro's short-term borrowing cost or the one-month Bankers' Acceptance rate plus a 1% Provincial Guarantee Fee which was equal to 2.2% as at March 31, 2014 (2013 – 2.2%). The effective interest rate for the year was 5.4% (2013 – 5.2 %) for the Non-Revolving Credit Facility and 2.1% (2013 – 2.1%) for the Revolving Credit Facility.

Once the principal amount of the advances under the Non-Revolving Credit Facility exceed $200 million, the interest rate is converted to a fixed rate equal to the Canadian Thirty Year Rate, which includes a 1% Provincial Guarantee Fee, in effect on the conversion date. The first conversion date was February 13, 2008, at which time the Canadian Thirty Year Rate was 5.9%. The second conversion date was July 14, 2009, at which time the Canadian Thirty Year Rate was 5.9%. The third conversion date was June 11, 2010, at which time the Canadian Thirty Year Rate was 5.7%. The fourth conversion date was May 13, 2011, at which time the Canadian Thirty Year Rate was 5.4%. The fifth conversion date was August 14, 2013, at which time the Canadian Thirty Year Rate was 5.1%.

The Interconnection Credit Facility consists of Manitoba Hydro advances received by the Partnership to fund the total capital cost to construct and install transmission facilities and interconnection system upgrades pursuant to the IOA with Manitoba Hydro. The interest rate on the Consolidated Interconnection Credit Facility is a fixed rate based on the weighted average of all Canadian Thirty Year Rates established for the Interconnection Credit Facility on June 29, 2012 and includes a 1.0% Provincial Guarantee Fee. The effective interest rate for the Interconnection Credit Facility for the year was 5.6% (2013 – 5.5%).

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

Principal payments on these loans are as follows:

	Total
	millions of dollars
2015	-
2016	-
2017	-
2018	-
2019	-
2020-2063	**1 350**
	1 350

NOTE 12 PARTNERS' CAPITAL

Authorized: Unlimited number of limited partnership units at $1 000 each.
Issued: 328 666.667 limited partnership units at $1 000 each.

As at March 31, limited partnership units issued were as follows:

	2014	2013
	units	
General Partner (5022649 Manitoba Ltd.)	**32.867**	32.675
Manitoba Hydro	**220 173.800**	218 889.825
Taskinigahp Power Corporation	**108 460.000**	107 827.500
	328 666.667	326 750.000

During the year ended March 31, 2014, WPLP issued 1 916.667 limited partnership units. These units have no preference, exchange, pre-emptive or redemption rights.

NOTE 13 FINANCIAL RISKS

Credit Risk
Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. The Partnership's financial asset that is exposed to credit risk is accounts receivable. This risk is minimal as it mainly relates to accounts receivable arising from the sale of power to Manitoba Hydro.

Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. The Partnership is exposed to interest rate risk associated with debt financing provided by Manitoba Hydro through variable-rate credit facilities.

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

Liquidity Risk
Liquidity risk refers to the risk that the Partnership will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, the Partnership uses cash generated from operations and credit facilities provided by Manitoba Hydro (Note 11).

NOTE 14 RELATED PARTY TRANSACTIONS

WPLP separately identifies within its records all transactions with Manitoba Hydro at the exchange amount as determined by various agreements. As at March 31, the following balances and transactions relate to Manitoba Hydro:

	2014	2013
	millions of dollars	
Revenue	**47**	25
Expenses		
Operating and administrative	**11**	5
Finance expense (Note 3)	**71**	41
Water rentals (Note 4)	**5**	3
Term Investment (Note 7)	**3**	1
Accounts receivable (Note 8)	**7**	4
Accounts payable	**22**	31
Interest payable (Note 10)	**17**	16
Long-term debt (Note 11)	**1 350**	1 288

Amounts paid to Manitoba Hydro include $22 million (2013 - $87 million) relating to the generating station, nil (2013 - $14 million) related to the transmission line, and $2 million (2013 - $4 million) in GST that was recovered from the Canada Revenue Agency with the exception of the accounts receivable noted above. Amounts received from Manitoba Hydro includes $2 million (2013 - $16 million) in equity contributions from both Manitoba Hydro and its wholly owned subsidiary, the General Partner.

WPLP has also entered into various agreements with Manitoba Hydro to provide services to the Partnership as follows:

a) the Construction Agreement, whereby Manitoba Hydro will construct the Wuskwatim generating station and related works;

b) the Project Financing Agreement, whereby Manitoba Hydro will provide debt financing to WPLP;

c) the Management Agreement, whereby Manitoba Hydro will provide administrative and management functions to WPLP;

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

d) the Maintenance and Operations Agreement, whereby Manitoba Hydro will provide all maintenance and on-site operations for the Wuskwatim generating station;

e) the IOA, whereby Manitoba Hydro will connect the Wuskwatim generating station to Manitoba Hydro's integrated power system;

f) the Systems Operation and Dispatch Agreement, whereby Manitoba Hydro will operate and dispatch the Wuskwatim generating station in an integrated fashion with Manitoba Hydro's integrated power system; and

g) the Power Purchase Agreement, whereby Manitoba Hydro will purchase from WPLP all of the power generated by the Wuskwatim generating station. WPLP is economically dependent on Manitoba Hydro as the sole purchaser of the power from Wuskwatim.

Amounts paid to Manitoba Hydro under the Management Agreement for the year ended March 31, 2014 totaled $1 million (2013 - $3 million).

NOTE 15 CAPITAL MANAGEMENT

Under the terms of the Wuskwatim PDA, WPLP maintains a 75:25 debt/equity ratio except for the first ten years following the final closing date when the amount may increase to 85% of the total capital cost less any advances made under the Revolving Credit Facility. Long-term debt financing is provided by Manitoba Hydro on an as-required basis. Manitoba Hydro also provides a $50 million revolving credit facility and a separate credit facility to finance the contributions to Manitoba Hydro for the construction of the transmission interconnection facilities necessary to connect the Wuskwatim generating station to the Manitoba Hydro system. The outstanding balance of this Interconnection Credit Facility is excluded from the calculation of the debt/equity ratio.

WPLP's debt ratio as at March 31 was as follows:

	2014	2013
	millions of dollars	
Long-term debt	**1 047**	984
Less: Cash and cash equivalents and term investment	**(3)**	(1)
Net debt	**1 044**	983
Partners' Capital	**222**	287
Debt ratio	**82%**	77%

WUSKWATIM POWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 16 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2013 have been reclassified in order to conform to the presentation adopted in 2014.

Financial Statements

Manitoba Hydro International Ltd.

March 31, 2014

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Manitoba Hydro International Ltd.

We have audited the accompanying consolidated financial statements of **Manitoba Hydro International Ltd.**, which comprise the consolidated balance sheet as at March 31, 2014, and the consolidated statements of income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Manitoba Hydro International Ltd.** as at March 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Winnipeg, Canada,
June 25, 2014.

Chartered Accountants

MANITOBA HYDRO INTERNATIONAL LTD.

CONSOLIDATED STATEMENT OF INCOME

For the year ended March 31

	Notes	2014	2013
		thousands of dollars	
Revenues		**51 096**	43 170
Cost of Operations			
Staff		**16 996**	14 272
Other direct costs	2	**15 149**	13 762
		32 145	28 034
Operating Profit		**18 951**	15 136
Expenses			
Operating and administrative		**9 699**	9 000
Depreciation		**1 188**	975
Capital and other taxes		**279**	239
		11 166	10 214
Income before other items		**7 785**	4 922
Other Items			
Interest income		**75**	47
Interest expense		**(1)**	(13)
		74	34
Net Income		**7 859**	4 956

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2014	2013
	thousands of dollars	
Retained earnings, beginning of year	**24 464**	19 508
Net income	**7 859**	4 956
Retained earnings, end of year	**32 323**	24 464

The accompanying notes are an integral part of the consolidated financial statements.

MANITOBA HYDRO INTERNATIONAL LTD.
CONSOLIDATED BALANCE SHEET
As at March 31

	Notes	**2014**	2013
		thousands of dollars	
Assets			
Property, Plant and Equipment			
In service	4	**10 505**	8 846
Less accumulated depreciation	4	**2 327**	1 678
		8 178	7 168
Current Assets			
Cash	6	**5 919**	4 090
Cash - restricted	6	**4 165**	4 460
Due from parent	8	**1 500**	-
Accounts receivable and accrued revenue	7	**18 425**	15 644
Prepaid expenses		**1 315**	3 855
		31 324	28 049
Other Assets			
Intangible assets	5	**638**	654
		40 140	35 871
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts payable	7	**4 001**	5 122
Deferred revenue	10	**1 463**	3 857
		5 464	8 979
Long-Term Deferred Revenue	10	**1 192**	1 267
Shareholder's Equity			
Share capital	12	**1 161**	1 161
Retained earnings		**32 323**	24 464
		33 484	25 625
		40 140	35 871

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MANITOBA HYDRO INTERNATIONAL LTD.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended March 31

	2014	2013
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**45 846**	40 496
Cash paid to suppliers and employees	**(40 704)**	(38 061)
Interest received	**75**	47
Interest paid	**(1)**	(13)
Cash provided by operating activities	**5 216**	2 469
Investing Activities		
Additions to property, plant and equipment	**(1 970)**	(1 587)
Additions to intangible assets	**(212)**	(215)
Term investment	**(1 500)**	-
Cash used for investing activities	**(3 682)**	(1 802)
Net increase in cash	**1 534**	667
Cash, beginning of year	**8 550**	7 883
Cash, end of year	**10 084**	8 550

The accompanying notes are an integral part of the consolidated financial statements.

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Manitoba Hydro International Ltd. (MHI), a wholly owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro), was incorporated in September 1998 and commenced operations April 1, 1999. As a wholly owned subsidiary of Manitoba Hydro, MHI is not subject to income taxes under Section 149(d) of the Income Tax Act (Canada), however MHI's foreign operations may be subject to income taxes in those jurisdictions.

MHI currently has four business segments, International Utility Services, Manitoba HVDC Research Centre, W.I.R.E. Services and Telecom Services. International Utility Services provides professional consulting, training and electricity infrastructure management services primarily to developing markets. The Manitoba HVDC Research Centre provides technology products, research and development and engineering services to the electrical power system industry. W.I.R.E. Services provides aerial LiDAR data collection and analysis to determine transmission line thermal ratings. Telecom Services provides state of the art broadband telecommunication solutions for telecom carriers, internet service providers and large commercial customers.

The consolidated financial statements include the accounts of MHI and its Nigerian and United Arab Emirates subsidiaries. For purposes of consolidation, all significant intercompany accounts and transactions have been eliminated.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) **Basis of Presentation**

These consolidated financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting – Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) **Property, Plant and Equipment**

Property, plant and equipment are recorded at cost. Depreciation is provided using the straight-line method over the following years to depreciate the assets over their estimated useful lives:

Leasehold improvements	20 years
Furniture and fixtures	20 years
Office, research, computer and telecom equipment	5 years

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

c) **Intangible Assets**

Intangible assets include computer software. They are recorded at cost and are amortized over their useful lives on a straight-line basis. The expected useful life is as follows:

Computer software	5 years

d) **Revenue Recognition**

Revenue is recognized when services are provided or goods are shipped to the customer. Revenue from maintenance and lease contracts is recognized on a straight-line basis over the term of the contract.

MHI recognizes revenue from fixed priced contracts under the percentage-of-completion method. The percentage of completion is determined by comparing the costs incurred as at the consolidated balance sheet date to the total estimated costs, which included costs incurred plus anticipated costs for completing a contract.

e) **Foreign Exchange**

Monetary items denominated in foreign currencies are translated into Canadian dollars at rates of exchange prevailing as at the consolidated balance sheet date. Revenues and expenses are translated at the rate of exchange prevailing at the date of the transaction. Foreign exchange gains and losses are included in income.

MHI's integrated foreign subsidiaries, located in Nigeria and the United Arab Emirates, are accounted for under the temporal method. Under this method, monetary assets and liabilities are translated at the exchange rate in effect as at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at historical rates. Revenues and expenses are translated at average rates for the period. Exchange gains or losses arising from the translation are included in operations.

f) **Research and Development Expenses**

Research expenses are charged to income in the year they are incurred. Development costs are charged to operations in the period of the expenditure unless a development project meets the criteria under Canadian GAAP for deferral and amortization.

g) **Other Direct Costs**

Other direct costs include transportation, accommodations, rents, project equipment, logistics, project bad debt expense, and other.

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

h) **Use of Estimates**

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements. Actual amounts could differ from those estimates. Key areas of estimation requiring management to make subjective judgements of matters that are inherently uncertain include the estimates for uncollectible accounts, provision for the useful lives of property, plant and equipment and intangibles. Significant changes in assumptions, including those with respect to future business plans and cash flows, could change the recorded amounts by a material amount.

NOTE 3 OPERATING LINE OF CREDIT

Manitoba Hydro provides MHI with a $1 million revolving line of credit to be used to fund its operations. The line of credit is payable on demand and bears interest at the average one-month Bankers' Acceptance rate. The effective rate for the fiscal year 2014 was nil (2013- nil). The amount outstanding on this operating line of credit as at March 31, 2014 is nil (2013 - nil).

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

			2014
	In service	**Accumulated depreciation**	**Net book value**
		thousands of dollars	
Leasehold improvements	**3 594**	**702**	**2 892**
Furniture and fixtures	**714**	**149**	**565**
Office, research, computer and telecom equipment	**6 197**	**1 476**	**4 721**
	10 505	**2 327**	**8 178**

			2013
	In service	Accumulated depreciation	Net book value
		thousands of dollars	
Leasehold improvements	3 561	524	3 037
Furniture and fixtures	704	113	591
Office, research, computer and telecom equipment	4 581	1 041	3 540
	8 846	1 678	7 168

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

Included in the cost above is $1 254 thousand (2013 - $700 thousand) of property, plant and equipment costs which have not been amortized as these assets were not placed in use as of year end.

NOTE 5 INTANGIBLE ASSETS

			2014
	In service	**Accumulated amortization**	**Net book value**
		thousands of dollars	
Computer software	**1 180**	**542**	**638**
	1 180	**542**	**638**

			2013
	In service	Accumulated amortization	Net book value
		thousands of dollars	
Computer software	1 067	413	654
	1 067	413	654

The additions to intangible assets for the year totaled $212 thousand (2013 - $215 thousand). In total, intangible assets of $228 thousand (2013 - $202 thousand) were amortized to operations during the year.

NOTE 6 CASH

	2014	2013
	thousands of dollars	
Cash - Canadian bank accounts	**4 980**	3 916
Cash - Overseas bank accounts	**939**	174
	5 919	4 090
Cash - Restricted	**4 165**	4 460
	10 084	8 550

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

Cash in overseas bank accounts includes funds deposited in foreign currencies in countries other than Canada. Restricted cash relates to deposits held for letters of guarantees for customer contracts. Cash balances earn interest at various rates based on monthly average balances. The effective interest rate for 2014 averaged 0.8% (2013 – 0.7%).

NOTE 7 RELATED PARTY TRANSACTIONS

During the normal course of business, MHI provided $3 105 thousand (2013 - $5 264 thousand) in services to Manitoba Hydro. During the year, Manitoba Hydro provided staffing to MHI at a cost recovery of $2 302 thousand (2013 - $2 336 thousand). MHI paid $521 thousand (2013 - $475 thousand) of expenses pertaining to the rental of fibre strands from Manitoba Hydro. MHI paid nil (2013 - nil) interest on its operating line of credit to Manitoba Hydro. Included in accounts payable is $572 thousand (2013 - $1 505 thousand) owing to Manitoba Hydro. Included in accounts receivable and accrued revenue is $513 thousand (2013 - $740 thousand) owing from Manitoba Hydro. Related party transactions are recorded at the exchange amount.

NOTE 8 DUE FROM PARENT

This balance represents an investment of $1 500 thousand (2013 - nil) in surplus cash that Manitoba Hydro has invested on behalf of MHI. This investment is redeemable within two business days on demand and interest earned is based on the average interest rate earned by Manitoba Hydro on its trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment. The effective interest rate as at March 31, 2014 was 1.0% (2013 - 1.0%).

NOTE 9 LEASE COMMITMENTS

As at March 31, 2014, future minimum annual lease payments committed under operating leases over the next five years are as follows:

Year 1	$554 thousand per year
Years 2-5	$592 thousand per year

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

NOTE 10 DEFERRED REVENUE

Deferred revenue pertains to the deferral of revenue from advance payments from customers. The associated revenue is recognized when the services are provided.

	2014	2013
	thousands of dollars	
Short-Term		
Software maintenance contracts	**621**	645
Dark fibre lease payment	**76**	76
Annual fibre lease contracts	**99**	99
Advance payments from international contracts	**667**	3 037
	1 463	3 857
Long-Term		
Software maintenance contracts	**395**	394
Dark fibre lease payment	**797**	873
	1 192	1 267
Total	**2 655**	5 124

NOTE 11 FINANCIAL RISKS

MHI is exposed to interest rate, foreign exchange, credit and liquidity risks. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by MHI, to set risk tolerance limits, to establish controls and to monitor risk and adherence to policies. The risk management plan is designed to ensure MHI's risks and exposures are in line with MHI's business objectives and risk tolerances. The nature of the financial risks and MHI's strategy for managing these risks has not changed significantly from the prior year.

Interest Rate Risk

Interest rate risk is associated with variable interest rates paid to the parent company, the Manitoba Hydro-Electric Board. The amount due to parent was nil at March 31, 2014 (2013 - nil).

Foreign Exchange Risk

Financial risk to MHI's operations arises from fluctuations in exchange rates and the volatility in these rates. MHI does not use derivative instruments to reduce its exposure to foreign currency

MANITOBA HYDRO INTERNATIONAL LTD.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2014

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risk. While MHI generates sales in a variety of countries, the sales contracts are based in Canadian dollars, U.S. dollars, Saudi Arabia Riyals, or Euros in order to reduce financial risk of foreign exchange. For the year ended March 31, 2014, realized foreign exchange translation gains of $667 thousand (2013- $119 thousand) are included in income.

Credit Risk

Credit risk arises from the potential that a counterparty will fail to perform its obligations. As at March 31, 2014, MHI is exposed to credit risk from customers in geographic areas primarily in Canada, Africa, Saudi Arabia, the United States, and Europe. MHI mitigates credit risk through the establishment of working relationships with customers and government agencies, and diversification to eliminate significant credit risk concentration.

Liquidity Risk

Liquidity risk refers to the risk that MHI will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, MHI uses cash generated from operations and has access to an operating line of credit from Manitoba Hydro. All accounts payable are due within 30 days of year end. See Note 9 for details of other contractual obligations and their maturities.

NOTE 12 SHARE CAPITAL

Unlimited number of common shares authorized and one common share issued. Shares in the capital of MHI cannot be sold, assigned, transferred or otherwise disposed of unless Manitoba Hydro will, after the disposition, continue to own directly or indirectly all of MHI's shares.

NOTE 13 PENSION PLAN

MHI has a defined contribution pension plan for its employees. MHI's contribution and expense for the year amounted to $224 thousand (2013 - $200 thousand) which is included in operating and administrative expenses. MHI does not carry any pension obligation on its consolidated financial statements for its defined contribution plan.

Unaudited Financial Statements of

TESHMONT LP HOLDINGS LTD.

March 31, 2014

TESHMONT LP HOLDINGS LTD.
STATEMENT OF INCOME AND RETAINED EARNINGS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Revenue		
Partnership income	**98**	436
Interest income	**21**	15
	119	451
Expenses	**19**	12
Net Income	**100**	439
Retained earnings, beginning of year	**5 511**	5 072
Retained earnings, end of year	**5 611**	5 511

The accompanying notes are an integral part of the financial statements.

TESHMONT LP HOLDINGS LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2014	2013
		thousands of dollars	
Assets			
Current Assets			
Cash		**9**	18
Term investments	3	**2 267**	2 256
		2 276	2 274
Other Assets			
Investment in partnership	4	**3 335**	3 237
		5 611	5 511
Other Liabilities			
Capital Tax		**-**	-
Shareholder's Equity			
Share capital		**-**	-
Retained earnings		**5 611**	5 511
		5 611	5 511
		5 611	5 511

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

TESHMONT LP HOLDINGS LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Operating Activities		
Proceeds from partnership income	-	599
Interest received	**21**	15
Cash paid to suppliers	**(19)**	(12)
Cash provided by operating activities	**2**	602
Investing Activities		
Term investments	**(11)**	(594)
Cash used for investing activities	**(11)**	(594)
Net increase (decrease) in cash	**(9)**	8
Cash, beginning of year	**18**	10
Cash, end of year	**9**	18

The accompanying notes are an integral part of the financial statements.

TESHMONT LP HOLDINGS LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Teshmont LP Holdings Ltd. (Teshmont Holdings) was established February 14, 2003 as a holding company of Manitoba Hydro to acquire a 40% ownership of Teshmont Consultants Limited Partnership (Teshmont LP), which carries on a high voltage engineering and consulting practice.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook - Accounting – Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

(b) **Revenue Recognition**

The investment in Teshmont LP is accounted for by the equity method.

(c) **Financial Instruments**

All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities.

Financial Instruments classified as other financial liabilities are measured at amortized cost using the effective method of amortization. Held-for-trading financial instruments are measured at fair value.

(d) **Use of Estimates**

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

TESHMONT LP HOLDINGS LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 3 TERM INVESTMENTS

Term investments include surplus cash of $2 267 thousand (2012 - $2 256 thousand) Manitoba Hydro has invested on behalf of Teshmont Holdings. The interest earned and paid on this investment will be based on the average interest rate earned by Manitoba Hydro on their trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment.

NOTE 4 INVESTMENT IN PARTNERSHIP

Teshmont Holdings investment in Teshmont LP is accounted for by the equity method where partnership income increases the investment and profit distributions decrease the investment.

	2014	2013
	thousands of dollars	
Opening Investment	**3 237**	3 400
Parternship Income	**98**	436
Distributions Received	**-**	(599)
Ending Investment	**3 335**	3 237

Financial Statements

Minell Pipelines Ltd.

March 31, 2014

EY
Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Minell Pipelines Ltd.

We have audited the accompanying financial statements of **Minell Pipelines Ltd.**, which comprise the balance sheet as at March 31, 2014, and the statements of income (loss), retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Minell Pipelines Ltd.** as at March 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Winnipeg, Canada,
June 25, 2014.

MINELL PIPELINES LTD.
STATEMENT OF INCOME (LOSS) AND RETAINED EARNINGS
For the year ended March 31

	Notes	2014	2013
		thousands of dollars	
Revenues			
Rental of gas transmission facilities		**198**	198
Expenses			
Operating and administrative	8	**75**	48
Finance expense	4	**14**	17
Depreciation and amortization		**39**	39
Capital and other taxes		**138**	130
		266	234
Net Loss		**(68)**	(36)
Retained earnings, beginning of year		**93**	129
Retained earnings, end of year		**25**	93

The accompanying notes are an integral part of the financial statements.

MINELL PIPELINES LTD.
BALANCE SHEET
As at March 31

	Notes	2014	2013
		thousands of dollars	
Assets			
Property, Plant and Equipment			
In service	5	**1 833**	1 833
Less accumulated depreciation	5	**903**	863
		930	970
Construction in progress	5	**848**	243
		1 778	1 213
Current Assets			
Prepaid expenses		**2**	2
Other Assets			
Regulated assets	6	**300**	320
		2 080	1 535
Liabilities and Shareholder's Equity			
Current Liabilities			
Due to parent	7	**1 725**	1 117
Accounts payable and accrued liabilities		**30**	24
		1 755	1 141
Contributions in Aid of Construction		**15**	16
Shareholder's Equity			
Share capital	10	**285**	285
Retained earnings		**25**	93
		310	378
		2 080	1 535

The accompanying notes are an integral part of the financial statements.
Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MINELL PIPELINES LTD.
STATEMENT OF CASH FLOWS
For the year ended March 31

	2014	2013
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**198**	198
Cash paid to suppliers	**(187)**	(159)
Interest paid	**(14)**	(17)
Cash (used for) provided by operating activities	**(3)**	22
Financing Activities		
Advance from parent company	**608**	71
Cash provided by financing activities	**608**	71
Investing Activities		
Additions to capital assets, net of contributions	**(605)**	(93)
Cash used for investing activities	**(605)**	(93)
Net change in cash	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**-**	-

The accompanying notes are an integral part of the financial statements.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Minell Pipelines Ltd. (Minell) operates a pipeline transmission system extending from Moosomin, Saskatchewan to Russell, Manitoba. This transmission system is approximately 70 kilometers in length and is used solely for the transportation of natural gas on behalf of Centra Gas Manitoba Inc. (Centra). Minell is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board and is regulated by the National Energy Board (NEB).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation - The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting - Pre-Changeover Accounting Standards and include the significant accounting policies described hereafter.

Rate Regulated Accounting - The rental charged for gas transmission facilities is subject to regulation by the NEB. The rate-setting process ensures that rates charged to customers recover all costs incurred in providing service. As permitted under Canadian GAAP, Minell applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Minell applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise have been included in the determination of net income in the year that the cost or credit is incurred. Minell refers to such deferred costs or credits as regulated assets (Note 6) or liabilities which are comprised of the following:

- Deferred taxes - As a result of the change in ownership in 1999, Minell became non-taxable and in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.

Minell's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Natural gas transmission systems and buildings and equipment are recorded at cost, which includes interest and overhead amounts capitalized during the construction period. Once the transfer to in-service property, plant and equipment is made, finance expense allocated to construction ceases and depreciation and finance expense charged to operations commences.

Depreciation is calculated on a straight-line basis at rates varying from 2.0% to 2.5% based on the estimated useful lives of the assets.

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

b) **Contributions in Aid of Construction**
Contributions in aid of construction are non-refundable contributions from customers in support of specific transmission facilities. These amounts are amortized to income at rates that correspond with the depreciation rates of the related assets.

c) **Revenue**
Revenue for the use of transmission facilities is from a related party and is recognized on a monthly basis.

d) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments classified as other financial liabilities are measured at amortized cost using the effective interest method of amortization.

e) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). As Minell has no items related to OCI, comprehensive income for the year is equivalent to net income.

f) **Use of Estimates**
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

NOTE 3 ACCOUNTING CHANGES

Future Accounting Changes

International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Minell would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Minell include property, plant and equipment, regulatory assets and liabilities and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus Improvements to IFRS, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Minell intends to apply this exemption.

In September 2010, the AcSB implemented changes to Part I of the CPA Canada Handbook –International Financial Reporting Standards allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Minell meets the AcSB criteria for deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On January 30, 2014, the IASB issued the interim standard IFRS 14 *Regulatory Deferral Accounts* for rate-regulated activities effective January 1, 2016 with earlier adoption permitted. Minell will early adopt the interim standard upon transition to IFRS effective April 1, 2015 and will continue to recognize regulatory deferral accounts for its financial reporting.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-Regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in modifications to existing IFRS prior to the commencement of Minell's 2015-16 fiscal year. Minell continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

NOTE 4 FINANCE EXPENSE

	2014	2013
	thousands of dollars	
Interest on amount due to parent	**23**	21
Interest capitalized	**(9)**	(4)
	14	17

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

	2014	2013
	thousands of dollars	
Land, buildings and equipment	**94**	94
Gas transmission	**1 739**	1 739
	1 833	1 833
Accumulated depreciation	**903**	863
	930	970
Construction in progress	**848**	243
	1 778	1 213

NOTE 6 REGULATED ASSETS

	2014	2013
	thousands of dollars	
Deferred taxes	**300**	320

If Minell was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the year that they were incurred and the net income for 2014 would have increased by $20 thousand (2013 – net income increased by $20 thousand).

In total, regulated assets of $20 thousand (2013 - $20 thousand) were amortized to operations during the year.

NOTE 7 DUE TO PARENT

	2014	2013
	thousands of dollars	
Amount due to parent	**1 725**	1 117

The amount due to the parent company bears interest at the three-month T-Bill rate plus a 1% Provincial Guarantee Fee on the outstanding balance and has no fixed terms of repayment. The effective rate for the period was 1.0% (2013 - 1.0%)

MINELL PIPELINES LTD.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 8 RELATED PARTY TRANSACTIONS

Rental of gas transmission facilities is to Centra Gas, a company under common control.

In addition to related party transactions disclosed elsewhere in the financial statements, operating and administrative expense includes $75 thousand (2013 - $48 thousand) for administrative and other services performed by Centra Gas. Related party transactions are recorded at the exchange amount.

NOTE 9 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of Minell's financial instruments at March 31 are as follows:

	2014		2013	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	thousands of dollars			
Other Financial Liabilities				
Accounts payable and accrued liabilities	**30**	**30**	24	24
Due to parent	**1 725**	**1 725**	1 117	1 117

Minell is exposed to interest rate risk associated with amounts due to the parent company.

NOTE 10 SHARE CAPITAL

	2014	2013
	thousands of dollars	
Share capital		
Authorized		
Unlimited number of shares of one class		
Issued		
285 000 shares	**285**	285

NOTE 11 CAPITAL MANAGEMENT

Minell meets its capital requirements through cash provided by operating activities and advances from its parent company, the Manitoba Hydro-Electric Board.

Unaudited Financial Statements of

MANITOBA HYDRO UTILITY SERVICES LIMITED

March 31, 2014

MANITOBA HYDRO UTILITY SERVICES LIMITED
STATEMENT OF INCOME AND RETAINED EARNINGS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Revenues		
Manitoba Hydro meter reading	**4 096**	3 916
Line locating	**13**	23
Other contracted services	**3**	3
Manitoba Hydro contracted services	**684**	562
Interactive voice response system	**116**	117
	4 912	4 621
Expenses		
Operating and administrative		
Wages and benefits	**4 103**	3 922
Equipment maintenance	**57**	78
Other operating and administrative	**593**	537
	4 753	4 537
Depreciation and amortization	**51**	64
Capital and other taxes	**78**	74
	4 882	4 675
Income (Loss) before other items	**30**	(54)
Other items		
Interest income	**14**	14
	14	14
Net Income (Loss)	**44**	(40)
Retained earnings, beginning of year	**1 721**	1 761
Retained earnings, end of year	**1 765**	1 721

The accompanying notes are an integral part of the financial statements.

MANITOBA HYDRO UTILITY SERVICES LIMITED
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2014	2013
		thousands of dollars	
Assets			
Property, Plant and Equipment			
Cost	3	**1 095**	1 032
Less accumulated amortization	3	**987**	935
		108	97
Current Assets			
Cash		**534**	63
Term investment	6	**1 425**	1 325
Accounts receivable	4	**415**	789
Prepaid expenses		**12**	17
		2 386	2 194
		2 494	2 291
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts payable and accrued liabilities	6 & 9	**729**	570
Shareholder's Equity			
Share capital	7	**-**	-
Retained earnings		**1 765**	1 721
		1 765	1 721
		2 494	2 291

The accompanying notes are an integral part of the financial statements.

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

MANITOBA HYDRO UTILITY SERVICES LIMITED
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Operating Activities		
Cash receipts from customers	**5 291**	4 266
Cash paid to suppliers and employees	**(4 672)**	(4 744)
Interest received	**14**	14
Cash provided by (used for) operating activities	**633**	(464)
Investing Activities		
Term investment	**(100)**	-
Additions to property, plant and equipment, net of disposals	**(62)**	(3)
Cash used for investing activities	**(162)**	(3)
Net increase (decrease) in cash	**471**	(467)
Cash, beginning of year	**63**	530
Cash, end of year	**534**	63

The accompanying notes are an integral part of the financial statements.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Manitoba Hydro Utility Services Limited (MHUS) is a wholly-owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro) and commenced operations on January 2, 1998. MHUS provides meter reading, interactive voice response systems and contracted services primarily to Manitoba Hydro and Centra Gas Manitoba Inc., a wholly-owned subsidiary of Manitoba Hydro.

As a wholly-owned subsidiary of Manitoba Hydro, MHUS is not subject to income taxes under section 149(d) of the Income Tax Act (Canada).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

a) **Basis of Presentation**
These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook - Accounting - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

b) **Property, Plant and Equipment**
Property, plant and equipment are recorded at cost. Depreciation is provided using the straight-line method. The following rates are designed to depreciate the assets over their estimated useful lives:

Furniture	10.0%
Office equipment	20.0%
Computer systems	10.0%
Computer hardware	20.0%
Meter reading devices	20.0%
Line locating equipment	20.0%

c) **Revenue**
Revenue is recognized as services are provided. Revenue from related parties is recorded at the exchange amount.

d) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of

the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities.

Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Held-for-trading financial instruments are measured at fair value.

e) **Employee Future Benefits**

MHUS full time employees are eligible for pension benefits under the Civil Service Superannuation Board (CSSB) defined benefit plan that provides pension benefits based on years of service.

MHUS is considered a matching employer under the Civil Service Superannuation Act (Act). Under the provisions of the Act, MHUS is required to match employee contributions at a prescribed contribution rate into the Civil Service Superannuation Fund (CSSF) pool of assets. MHUS does not carry any pension obligation value on its financial statements.

Pension expenses for MHUS employees are recognized at the time contributions are made to the Civil Service Superannuation Fund (CSSF), which maintains the funds and obligations relating to these employees in its financial records.

Other benefits earned by employees include vacation, banked sick leave and incentive compensation. Where applicable, the future costs of these benefits are based on management's best estimates.

f) **Use of Estimates**

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual results could differ from those estimates, but differences are not expected to be material.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 3 PROPERTY, PLANT AND EQUIPMENT

			2014
	Cost	Accumulated Amortization	Net book value
	thousands of dollars		
Furniture	**30**	**23**	**7**
Office equipment	**12**	**12**	**-**
Computer systems	**86**	**86**	**-**
Computer hardware	**186**	**177**	**9**
Line locating equipment	**24**	**24**	**-**
Meter reading devices	**757**	**665**	**92**
	1 095	**987**	**108**

			2013
	Cost	Accumulated Amortization	Net book value
	thousands of dollars		
Furniture	30	21	9
Office equipment	12	12	-
Computer systems	85	85	-
Computer hardware	183	168	15
Line locating equipment	24	24	-
Meter reading devices	698	625	73
	1 032	935	97

NOTE 4 ACCOUNTS RECEIVABLE

	2014	2013
	thousands of dollars	
Manitoba Hydro	**403**	783
Other	**12**	6
	415	789

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 5 LEASE COMMITMENTS

MHUS leases its premises from Manitoba Hydro. The lease requires payments of approximately $19 thousand per year (2013 - $12 thousand). In addition, MHUS is responsible for payment of property taxes which approximate $9 thousand annually (2013 - $2 thousand). The lease was renewed in December 2013 and will expire in November 2015 with a one year extension option. Rent and rates were adjusted in the renewed lease based on City of Winnipeg Assessment & Taxation data.

NOTE 6 RELATED PARTY TRANSACTIONS

MHUS identifies all financial transactions with Manitoba Hydro separately in its records at the exchange amount. During the year, Manitoba Hydro provided $212 thousand (2013 - $266 thousand) in services to MHUS. Amounts due to Manitoba Hydro in the amount of $21 thousand (2013 - $36 thousand) are included in accounts payable and accrued liabilities. MHUS paid $15 thousand (2013 - $12 thousand) rent to Manitoba Hydro. MHUS provided $4 923 thousand (2013 - $4 632 thousand) in services to Manitoba Hydro. Amounts receivable from Manitoba Hydro in the amount of $368 thousand (2013 - $751 thousand) are included in accounts receivable. MHUS has made a term investment of surplus cash of $1 425 thousand (2013 - $1 325 thousand) which Manitoba Hydro has invested on its behalf. The interest earned and paid on this investment will be based on the average interest rate earned by Manitoba Hydro on their trust investments over the same period, or the average of the overnight investment rates as quoted by the Province of Manitoba over the term of the investment.

NOTE 7 SHARE CAPITAL

An unlimited number of Class A and Class B shares authorized and ten (10) Class A shares issued. Class B shares are redeemable and retractable and are not entitled to dividends.

NOTE 8 FINANCIAL RISKS

Credit Risk
Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. MHUS's financial asset that is exposed to credit risk is accounts receivable. This risk is minimal as it mainly relates to accounts receivable arising from services provided to Manitoba Hydro.

MANITOBA HYDRO UTILITY SERVICES LIMITED
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in the market interest rates. MHUS is exposed to interest rate risk associated with debt financing provided by Manitoba Hydro through variable-rate credit facilities. As at March 31, 2014 the amount of financing outstanding is nil (2013 - nil).

NOTE 9 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Included in accounts payable and accrued liabilities as at March 31, 2014 are government remittances payable of $6 245 (2013 - $19 420) relating to Manitoba payroll tax and Manitoba Workers' Compensation Board insurance.

Financial Statements

Keeyask Hydropower Limited Partnership

March 31, 2014

EY
Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Partners of
Keeyask Hydropower Limited Partnership

We have audited the accompanying financial statements of **Keeyask Hydropower Limited Partnership**, which comprise of the balance sheet as at March 31, 2014, and the statement of partners' capital and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Keeyask Hydropower Limited Partnership** as at March 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Ernst & Young LLP

Chartered Accountants

Winnipeg, Canada,
June 25, 2014.

Financial Statements of

KEEYASK HYDROPOWER LIMITED PARTNERSHIP

March 31, 2014

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
BALANCE SHEET
As at March 31

	Notes	2014	2013
		dollars	
Assets			
Current Assets			
Cash		**10 000**	10 000
		10 000	10 000
Equity			
Partners' capital	3	**10 000**	10 000
		10 000	10 000

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Bruce A. Barrett, P.Eng.
President of the general partner of KHLP
(5900345 Manitoba Ltd.)

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
STATEMENT OF PARTNERS' CAPITAL
For the year ended March 31

	Class	**Units as at March 31, 2014**	**Capital as at March 31, 2014**	Units as at March 31, 2013	Capital as at March 31, 2013
			dollars		*dollars*
Manitoba Hydro	M	**7 499**	**8 249**	7 499	8 249
General Partner (5900345 Manitoba Ltd.)	M	**1**	**1**	1	1
Cree Nation Partners Limited Partnership	K	**1 050**	**1 050**	1 050	1 050
	E	**450**	**-**	450	-
FLCN Keeyask Investments Inc.	K	**350**	**350**	350	350
	E	**150**	**-**	150	-
York Factory First Nation Limited Partnership	K	**350**	**350**	350	350
	E	**150**	**-**	150	-
		10 000	**10 000**	10 000	10 000

The accompanying notes are an integral part of the financial statements.

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
STATEMENT OF CASH FLOWS
For the year ended March 31

	2014	2013
	dollars	
Financing Activities		
Proceeds from issue of units of KHLP	-	-
Cash provided by financing activities	**-**	-
Net increase in cash	**-**	-
Cash, beginning of year	**10 000**	10 000
Cash, end of year	**10 000**	10 000

The accompanying notes are an integral part of the financial statements.

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

Keeyask Hydropower Limited Partnership (KHLP or the Partnership) was formed on July 30, 2009 under the laws of Manitoba to carry on the business of developing, owning and operating the Keeyask hydroelectric generating station (the Project) and related works excluding the transmission facilities but including the powerhouse and spillway and all dams, dikes, channels, excavations and roads to be located in the vicinity of Gull Rapids, upstream of the point at which the Nelson River flows into Stephens Lake.

An agreement was reached between Manitoba Hydro and Tataskweyak Cree Nation (TCN) and War Lake First Nation (War Lake) operating as Cree Nation Partners (CNP), York Factory First Nation (York Factory) and Fox Lake Cree Nation (Fox Lake) on the development of the Project pursuant to the Joint Keeyask Development Agreement (the JKDA) signed on May 29, 2009.

Manitoba Hydro, Cree Nation Partners Limited Partnership (CNPLP) (owned beneficially by TCN and War Lake through CNP), FLCN Keeyask Investments Inc. (FLCNKII) (owned beneficially by Fox Lake) and York Factory First Nation Limited Partnership (YFFNLP) (owned beneficially by York Factory) are limited partners of KHLP. 5900345 Manitoba Ltd. (the General Partner), which is a wholly owned subsidiary of Manitoba Hydro, also owns a nominal interest in KHLP.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP").

KEEYASK HYDROPOWER LIMITED PARTNERSHIP
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2014

NOTE 3 PARTNERS' CAPITAL

Authorized Unlimited number of limited partnership units (Class E, K and M)

Issued	Manitoba Hydro	7 499	Class M Units	74.99%
	General Partner	1	Class M Unit	0.01%
	CNPLP	1 050	Class K Units	10.50%
		450	Class E Units	4.50%
	FLCNKII	350	Class K Units	3.50%
		150	Class E Units	1.50%
	YFFNLP	350	Class K Units	3.50%
		150	Class E Units	1.50%
	Total	10 000	Class M, K and E Units	100.00%

The units have no preference, exchange, pre-emptive or redemption rights.

Unaudited Financial Statements of

5022649 MANITOBA LTD.

March 31, 2014

5022649 MANITOBA LTD.
STATEMENT OF LOSS AND RETAINED EARNINGS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Partnership Loss	**(7)**	(4)
Retained earnings, beginning of year	**(4)**	-
Retained earnings, end of year	**(11)**	(4)

The accompanying notes are an integral part of the financial statements.

5022649 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2014	2013
		thousands of dollars	
Assets			
Current Assets			
Cash		**4**	4
Other Assets			
Investment in Partnership	3	**22**	29
		26	33
Shareholders' Equity			
Share capital	4	**37**	37
Retained earnings		**(11)**	(4)
		26	33

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Lorne Midford, P.Eng.
Chair of the general partner of WPLP
(5022649 Manitoba Ltd.)

Darren B. Rainkie, CA
Treasurer and Chair of the
Audit Committee

5022649 MANITOBA LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Financing Activities		
Proceeds from common share issue	-	-
Cash provided by financing activities	-	-
Investing Activities		
Investment in partnership	-	(3)
Cash used for investing activities	-	(3)
Net decrease in cash	-	(3)
Cash, beginning of year	4	7
Cash, end of year	4	4

The accompanying notes are an integral part of the financial statements.

5022649 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

5022649 Manitoba Ltd. was incorporated on November 30, 2004 and is a wholly owned subsidiary of Manitoba Hydro. This company is the General Partner of the Wuskwatim Power Limited Partnership (Partnership) and has acquired .01% ownership of the Partnership.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

(b) **Revenue Recognition**

The investment in the Partnership is accounted for by the equity method.

NOTE 3 INVESTMENT IN PARTNERSHIP

5022649 Manitoba Ltd.'s investment in the Partnership is accounted for using the equity method where contributions to the Partnership increase the investment and the General Partner's share of the Partnership loss decreases the investment.

	2014	2013
	thousands of dollars	
Investment in Partnership, beginning of year	**29**	30
Contributions to Partnership	**-**	3
Partnership loss	**(7)**	(4)
Investment in Partnership, end of year	**22**	29

NOTE 4 SHARE CAPITAL

An unlimited number of common shares are authorized and 3 700 common shares have been issued.

Unaudited Financial Statements of

5900345 MANITOBA LTD.

March 31, 2014

5900345 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2014	2013
		dollars	
Assets			
Current Assets			
Cash		**1 000**	1 000
Other Assets			
Investment in Keeyask Hydropower Limited Partnership		**1**	1
		1 001	1 001
Shareholder's Equity			
Share Capital	3	**1 001**	1 001
		1 001	1 001

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Bruce A. Barrett, P.Eng.
President of the general partner of KHLP
(5900345 Manitoba Ltd.)

5900345 MANITOBA LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2014	2013
	dollars	
Financing Activities		
Proceeds from common share issue	-	-
Cash provided by financing activities	-	-
Investing Activities		
Investment in Partnership	-	-
Cash used for investing activities	-	-
Net increase in cash	-	-
Cash, beginning of year	**1 000**	1 000
Cash, end of year	**1 000**	1 000

The accompanying notes are an integral part of the financial statements.

5900345 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

5900345 Manitoba Ltd. was incorporated on June 17, 2009 and is a wholly owned subsidiary of Manitoba Hydro. This company is the General Partner of the Keeyask Hydropower Limited Partnership and has acquired .01% ownership of the Partnership.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook – Accounting - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

NOTE 3 SHARE CAPITAL

An unlimited number of common shares authorized and 1001 common shares issued.

Unaudited Financial Statements of

4985371 MANITOBA LTD.

March 31, 2014

4985371 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Note	2013	2012
		dollars	
Assets			
Cash		**1**	1
		1	1
Shareholder's Equity			
Share Capital	2	**1**	1
		1	1

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

4985371 MANITOBA LTD.

NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)

For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

4985371 Manitoba Ltd was established September 14, 2004 to hold legal title of the property at 360 Portage Avenue. As a bare trustee, 4985371 Manitoba Ltd holds title to the property without any further duty to perform, except convey title to the beneficiary, Manitoba Hydro, upon demand.

NOTE 2 SHARE CAPITAL

An unlimited number of Class A common shares authorized and one Class A common share issued.

Unaudited Financial Statements of

6690271 MANITOBA LTD.

March 31, 2014

6690271 MANITOBA LTD.
BALANCE SHEET (UNAUDITED)
As at March 31

	Notes	2014	2013
		thousands of dollars	
Assets			
Current Assets			
Cash		**12**	-
Fixed Assets			
Work in Progress		**6 792**	-
		6 804	-
Liabilities and Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**624**	-
Intercompany payable		**3 887**	-
		4 511	-
Equity			
Share capital	3	**2 293**	-
		6 804	-

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

Lorne Midford, P.Eng.
President

6690271 MANITOBA LTD.
STATEMENT OF CASH FLOWS (UNAUDITED)
For the year ended March 31

	2014	2013
	thousands of dollars	
Investing Activities		
Work in progress	(2 281)	-
Cash used for investing activities	**(2 281)**	-
Financing Activities		
Proceeds from issue of common shares	2 293	-
Cash provided by financing activities	**2 293**	-
Net change in cash	**12**	-
Cash and cash equivalents, beginning of year	-	-
Cash and cash equivalents, end of year	**12**	-

The accompanying notes are an integral part of the financial statements.

6690271 MANITOBA LTD.
NOTES TO THE FINANCIAL STATEMENTS (UNAUDITED)
For the year ended March 31, 2014

NOTE 1 NATURE OF THE ORGANIZATION

6690271 Manitoba Ltd. was incorporated on April 8, 2013 and is a wholly owned subsidiary of Manitoba Hydro. This company was formed to fund a portion of the US segment of the new international transmission interconnection, the Great Northern Transmission Line, being constructed by Minnesota Power.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) **Basis of Presentation**

These financial statements were prepared in accordance with Part II of the Chartered Professional Accountants (CPA) Canada Handbook - Accounting - Canadian Accounting Standards for Private Enterprises, which sets out generally accepted accounting principles for non-publicly accountable enterprises in Canada ("GAAP") and include the significant accounting policies described hereafter.

NOTE 3 SHARE CAPITAL

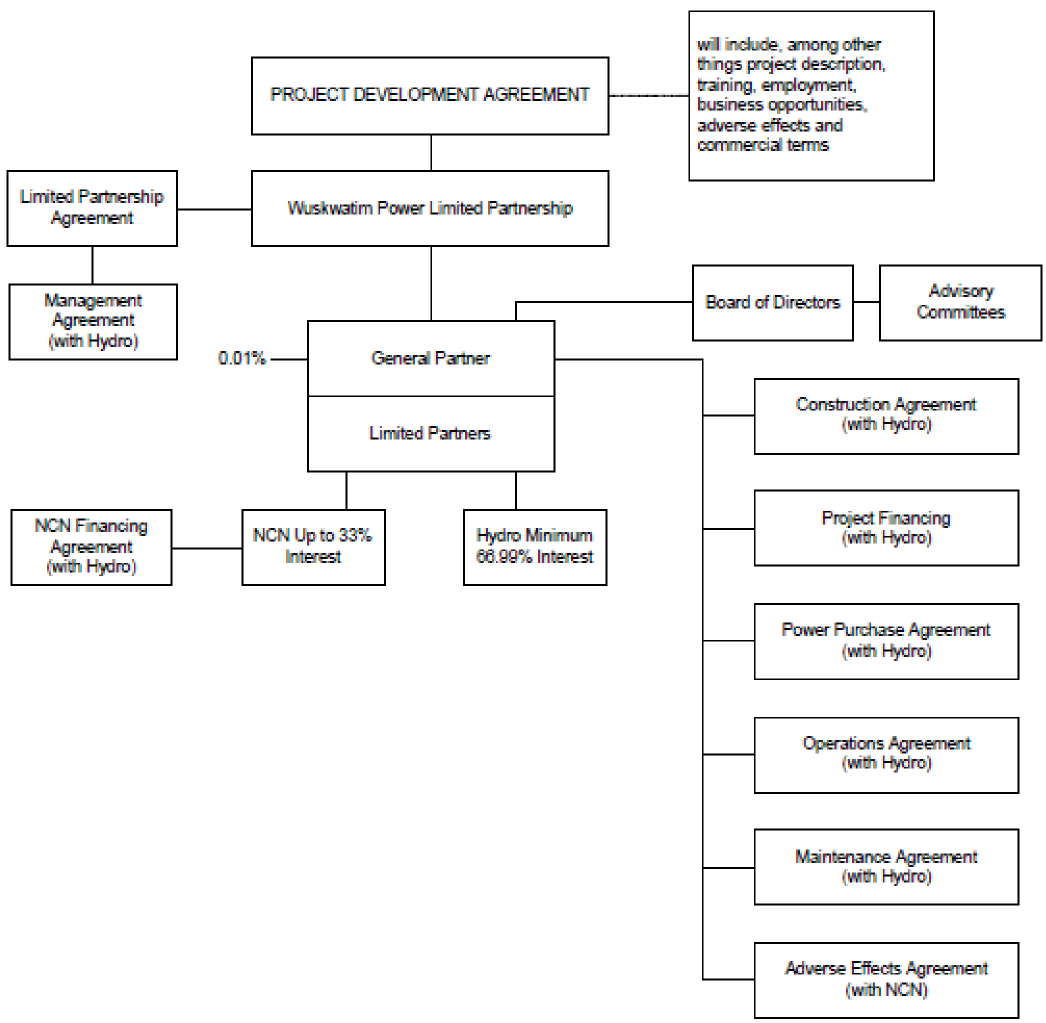
Unlimited number of common shares authorized at one dollar each and 2 293 482 common shares were issued.

Corporate Overview MFR 7

Updated Ownership schematic for WPLP and KHLP.

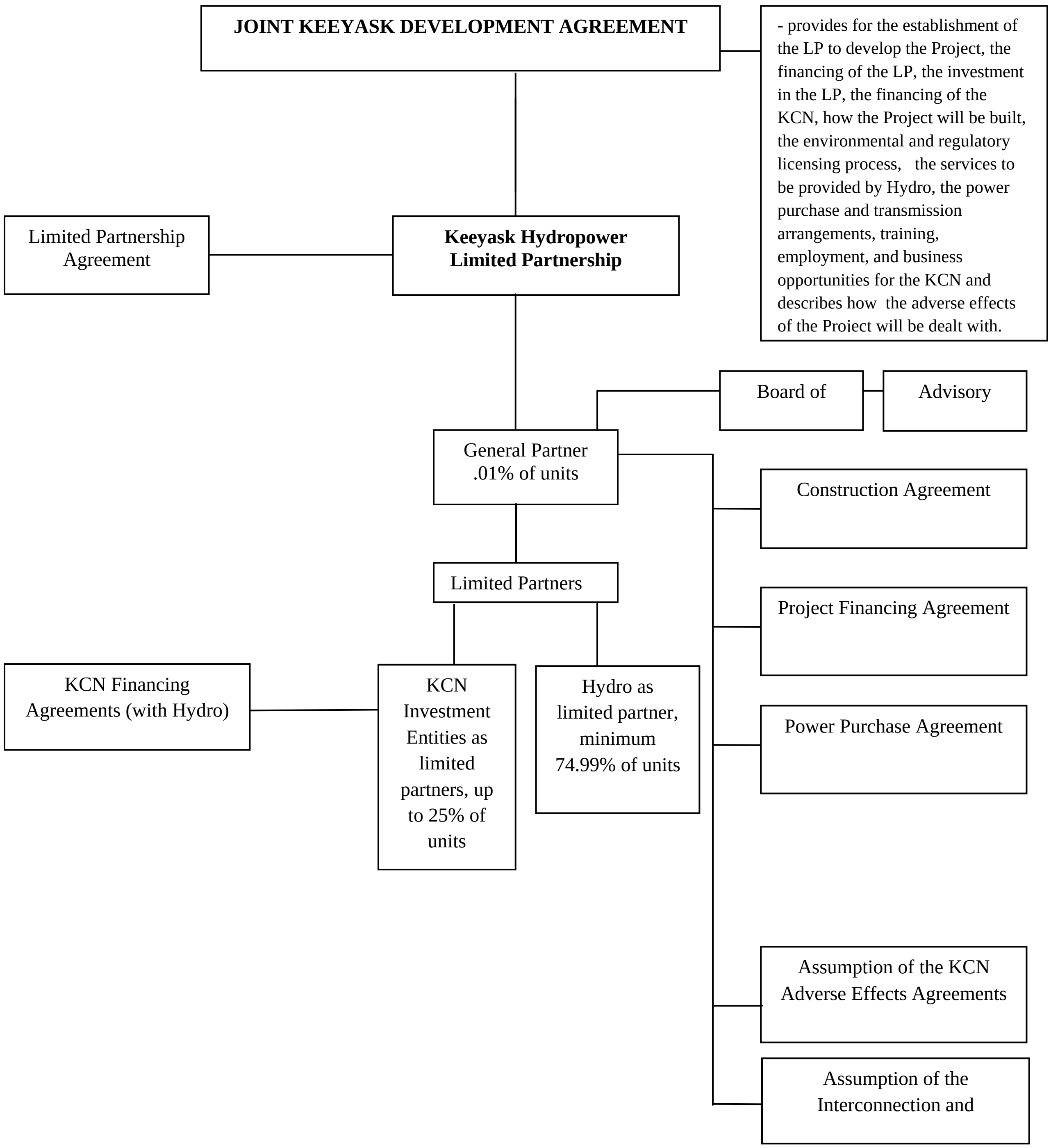
Figure 2.4 below was included in the Needs For and Alternatives to the Wuskwatim Project (NFAAT) submission to the Manitoba Clean Environment Commission in 2003 and is representative of the current ownership structure of the partnership. As at the date of this Application, NCN is fully invested at a 33% ownership interest in WPLP.

FIGURE 2.4 AGREEMENT FRAMEWORK AND EQUITY OWNERSHIP FOR THE PROJECT



Schedule 2-1 from the Joint Keeyask Development Agreement (JKDA) is representative of the current ownership structure of the partnership. As of the date of this Application, the KCN have a 17.5% ownership interest in KHLP (with an option to activate the incremental 7.5% at future points in time).

SCHEDULE 2-1



Corporate Overview MFR 8

Financial Forecasts for WPLP and KHLP

Please find attached the 2014 projected financial statements for WPLP and KHLP.

The WPLP forecast assumes terms of the agreement in principle with NCN commencing in 2014/15.

The KHLP forecast assumes the KCN's will hold a 17.5% common ownership interest up to June of 2021 and then elect to invest in the preferred ownership option.

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
Revenue	41	82	98	103	107	111	114	119	124	129
	41	82	98	103	107	111	114	119	124	129
EXPENSES										
Operating and Administrative	13	12	12	12	12	13	13	13	13	13
Finance Expense	74	75	77	79	79	79	77	76	75	73
Depreciation and Amortization	26	27	27	27	27	27	27	27	27	27
Water Rentals and Assessments	5	5	5	5	5	5	5	5	5	5
	119	119	121	123	124	123	122	121	120	119
Net Income	(77)	(37)	(23)	(21)	(17)	(13)	(9)	(2)	4	11
Financial Ratios										
Debt	89%	91%	93%	95%	95%	95%	95%	95%	95%	93%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
Revenue	134	121	124	128	130	135	140	145	151	156
	134	121	124	128	130	135	140	145	151	156
EXPENSES										
Operating and Administrative	14	14	14	14	15	11	11	11	11	11
Finance Expense	71	70	67	65	62	60	57	53	51	50
Depreciation and Amortization	27	27	27	27	27	27	27	27	27	27
Water Rentals and Assessments	5	5	5	5	5	5	5	5	5	5
	117	116	113	111	109	103	100	96	94	94
Net Income	17	5	11	17	21	32	40	49	56	63
Financial Ratios										
Debt	92%	91%	90%	88%	85%	81%	76%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	1,345	1,345	1,375	1,375	1,375	1,375	1,375	1,375	1,378	1,378
Accumulated Depreciation	(52)	(72)	(92)	(113)	(134)	(155)	(175)	(196)	(217)	(238)
Net Plant in Service	1,293	1,273	1,283	1,262	1,241	1,220	1,199	1,179	1,161	1,140
Construction in Progress	2	15	-	-	-	-	-	-	-	-
Current and Other Assets	298	304	310	316	324	332	340	349	358	368
	1,594	1,592	1,592	1,578	1,565	1,552	1,540	1,528	1,520	1,509
LIABILITIES AND EQUITY										
Long-Term Debt	1,302	1,301	1,300	1,298	1,297	1,295	1,294	1,292	1,290	1,288
Current and Other Liabilities	144	180	205	213	207	197	188	179	170	150
Partners Capital	147	110	87	66	61	60	58	57	60	71
	1,594	1,592	1,592	1,578	1,565	1,552	1,540	1,528	1,520	1,509
Debt Ratio	89%	91%	93%	95%	95%	95%	95%	95%	95%	93%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,382	1,382
Accumulated Depreciation	(259)	(279)	(300)	(321)	(342)	(363)	(384)	(404)	(425)	(446)
Net Plant in Service	1,120	1,099	1,078	1,057	1,036	1,015	995	974	957	936
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	379	389	401	413	425	438	451	465	480	496
	1,498	1,488	1,479	1,470	1,461	1,453	1,446	1,439	1,437	1,432
LIABILITIES AND EQUITY										
Long-Term Debt	1,286	1,284	1,281	1,279	1,276	1,273	1,270	1,267	1,264	1,261
Current and Other Liabilities	125	111	94	70	43	5	(40)	(35)	(27)	(21)
Partners Capital	88	93	104	121	142	174	215	207	201	193
	1,498	1,488	1,479	1,470	1,461	1,453	1,446	1,439	1,437	1,432
Debt Ratio	92%	91%	90%	88%	85%	81%	76%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	41	82	98	103	107	111	114	119	124	129
Cash Paid to Suppliers and Employees	(18)	(17)	(17)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
Interest Paid	(74)	(76)	(78)	(80)	(81)	(81)	(81)	(80)	(79)	(78)
Interest Received	-	0	1	1	2	3	3	4	4	5
	(51)	(11)	3	6	11	15	18	26	31	38
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	1	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
	1	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(9)	(12)	(14)	-	-	-	-	-	(3)	-
Sinking Fund Payment	(10)	(12)	(12)	(13)	(14)	(14)	(15)	(15)	(16)	(16)
Other	-	-	-	-	-	11	11	7	-	-
	(19)	(24)	(26)	(13)	(14)	(3)	(4)	(8)	(19)	(16)
Net Increase (Decrease) in Cash	(69)	(36)	(25)	(8)	(5)	10	13	16	10	19
Cash at Beginning of Year	(48)	(117)	(152)	(178)	(186)	(191)	(181)	(168)	(152)	(142)
Cash at End of Year	(117)	(152)	(178)	(186)	(191)	(181)	(168)	(152)	(142)	(123)

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	134	121	124	128	130	135	140	145	151	156
Cash Paid to Suppliers and Employees	(19)	(19)	(19)	(19)	(20)	(16)	(16)	(16)	(16)	(16)
Interest Paid	(77)	(76)	(75)	(74)	(73)	(71)	(69)	(67)	(66)	(66)
Interest Received	6	6	9	10	11	12	12	13	15	16
	44	33	38	44	49	59	68	76	84	90
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	-	-	-	-	-	-	-	-	(4)	-
Sinking Fund Payment	(17)	(17)	(18)	(18)	(19)	(19)	(20)	(21)	(21)	(22)
Other	-	-	-	-	-	-	-	-	(57)	(63)
	(17)	(17)	(18)	(18)	(19)	(19)	(20)	(21)	(82)	(85)
Net Increase (Decrease) in Cash	25	13	18	23	27	37	45	53	(2)	1
Cash at Beginning of Year	(123)	(97)	(84)	(66)	(43)	(16)	22	67	119	117
Cash at End of Year	(97)	(84)	(66)	(43)	(16)	22	67	119	117	118

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
Revenue	-	-	-	-	-	35	226	286	298	315
	-	-	-	-	-	35	226	286	298	315
EXPENSES										
Operating and Administrative	-	-	-	-	-	5	14	14	14	15
Finance Expense	0	0	0	0	0	20	181	247	248	247
Depreciation and Amortization	-	-	-	-	-	6	62	85	85	85
Water Rentals and Assessments	-	-	-	-	-	2	13	15	19	20
	0	0	0	0	0	32	270	361	367	367
Net Income	(0)	(0)	(0)	(0)	(0)	2	(44)	(74)	(69)	(52)
Financial Ratios										
Debt	75%	75%	75%	75%	75%	75%	75%	76%	77%	78%

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
Revenue	324	318	324	331	337	349	361	370	384	399
	324	318	324	331	337	349	361	370	384	399
EXPENSES										
Operating and Administrative	15	15	15	15	15	15	14	15	15	15
Finance Expense	248	246	242	240	237	234	229	225	215	209
Depreciation and Amortization	85	85	85	85	85	85	85	85	85	85
Water Rentals and Assessments	20	20	20	20	20	21	21	21	22	22
	368	366	363	360	358	355	350	346	337	332
Net Income	(44)	(48)	(38)	(29)	(21)	(6)	11	25	47	67
Financial Ratios										
Debt	78%	79%	79%	80%	80%	79%	79%	75%	75%	75%

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	-	-	-	-	-	2,541	5,929	5,929	5,929	5,929
Accumulated Depreciation	-	-	-	-	-	(6)	(65)	(146)	(227)	(308)
Net Plant in Service	-	-	-	-	-	2,535	5,864	5,783	5,701	5,620
Construction in Progress	1,666	2,303	3,196	4,449	5,240	3,175	(51)	(5)	(0)	0
Current and Other Assets	14	27	56	94	149	199	199	238	278	322
	1,681	2,330	3,252	4,543	5,389	5,908	6,011	6,016	5,980	5,942
LIABILITIES AND EQUITY										
Long-Term Debt	1,014	1,627	2,256	3,294	3,949	4,199	4,401	4,400	4,399	4,552
Current and Other Liabilities	277	155	225	164	158	306	211	279	312	174
Partners Capital	389	548	771	1,084	1,282	1,403	1,399	1,336	1,268	1,216
	1,681	2,330	3,252	4,543	5,389	5,908	6,011	6,016	5,980	5,942
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	76%	77%	78%

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	5,929	5,929	5,929	5,929	5,929	5,932	5,932	5,932	5,932	5,932
Accumulated Depreciation	(390)	(471)	(552)	(633)	(715)	(796)	(877)	(958)	(1,040)	(1,121)
Net Plant in Service	5,539	5,458	5,376	5,295	5,214	5,137	5,055	4,974	4,893	4,812
Construction in Progress	0	0	0	0	0	0	0	0	0	0
Current and Other Assets	367	414	463	515	568	624	682	743	806	872
	5,905	5,871	5,839	5,810	5,782	5,761	5,738	5,717	5,699	5,683
LIABILITIES AND EQUITY										
Long-Term Debt	4,550	4,549	4,548	4,547	4,545	4,544	4,542	4,540	4,539	4,537
Current and Other Liabilities	182	198	205	206	201	187	155	(75)	14	0
Partners Capital	1,173	1,124	1,086	1,057	1,036	1,030	1,041	1,252	1,146	1,146
	5,905	5,871	5,839	5,810	5,782	5,761	5,738	5,717	5,699	5,683
Debt Ratio	78%	79%	79%	80%	80%	79%	79%	75%	75%	75%

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	-	-	-	-	-	35	226	286	298	315
Cash Paid to Suppliers and Employees	-	-	-	-	-	(7)	(27)	(29)	(34)	(34)
Interest Paid	(15)	(56)	(83)	(122)	(176)	(212)	(233)	(241)	(244)	(245)
Interest Received	-	-	-	-	-	-	-	-	2	4
	(15)	(56)	(83)	(122)	(176)	(184)	(34)	16	22	39
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,000	600	600	1,000	600	200	200	-	-	154
Other	371	154	218	308	193	113	34	6	(5)	(6)
	1,371	754	818	1,308	793	313	234	6	(5)	147
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,515)	(571)	(797)	(1,114)	(604)	(274)	(100)	(47)	(4)	(0)
Sinking Fund Payment	-	-	-	-	-	-	-	(43)	(45)	(47)
Other	-	-	-	-	-	-	-	-	-	-
	(1,515)	(571)	(797)	(1,114)	(604)	(274)	(100)	(89)	(49)	(47)
Net Increase (Decrease) in Cash	(159)	127	(62)	72	14	(144)	100	(67)	(32)	139
Cash at Beginning of Year	-	(159)	(32)	(94)	(22)	(8)	(153)	(53)	(120)	(152)
Cash at End of Year	(159)	(32)	(94)	(22)	(8)	(153)	(53)	(120)	(152)	(13)

KEEYASK HYDROPOWER LIMITED PARTNERSHIP (IFF14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	324	318	324	331	337	349	361	370	384	399
Cash Paid to Suppliers and Employees	(35)	(35)	(35)	(35)	(36)	(36)	(35)	(36)	(37)	(37)
Interest Paid	(248)	(248)	(249)	(249)	(249)	(248)	(247)	(245)	(239)	(236)
Interest Received	6	8	12	15	17	20	23	27	30	33
	47	43	53	62	70	85	102	116	139	158
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	(6)	(7)	(7)	(7)	(7)	(6)	(6)	(6)	(6)	(7)
	(6)	(7)	(7)	(7)	(7)	(6)	(6)	(6)	(6)	(7)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	-	-	-	-	-	(4)	-	-	-	-
Sinking Fund Payment	(49)	(51)	(53)	(55)	(58)	(60)	(62)	(64)	(67)	(70)
Other	-	-	-	-	-	-	-	-	186	(153)
	(49)	(51)	(53)	(55)	(58)	(64)	(62)	(64)	119	(223)
Net Increase (Decrease) in Cash	(8)	(15)	(7)	(0)	6	15	33	45	252	(72)
Cash at Beginning of Year	(13)	(22)	(37)	(44)	(44)	(39)	(23)	10	55	307
Cash at End of Year	(22)	(37)	(44)	(44)	(39)	(23)	10	55	307	235

<u>Corporate Overview MFR 10</u>

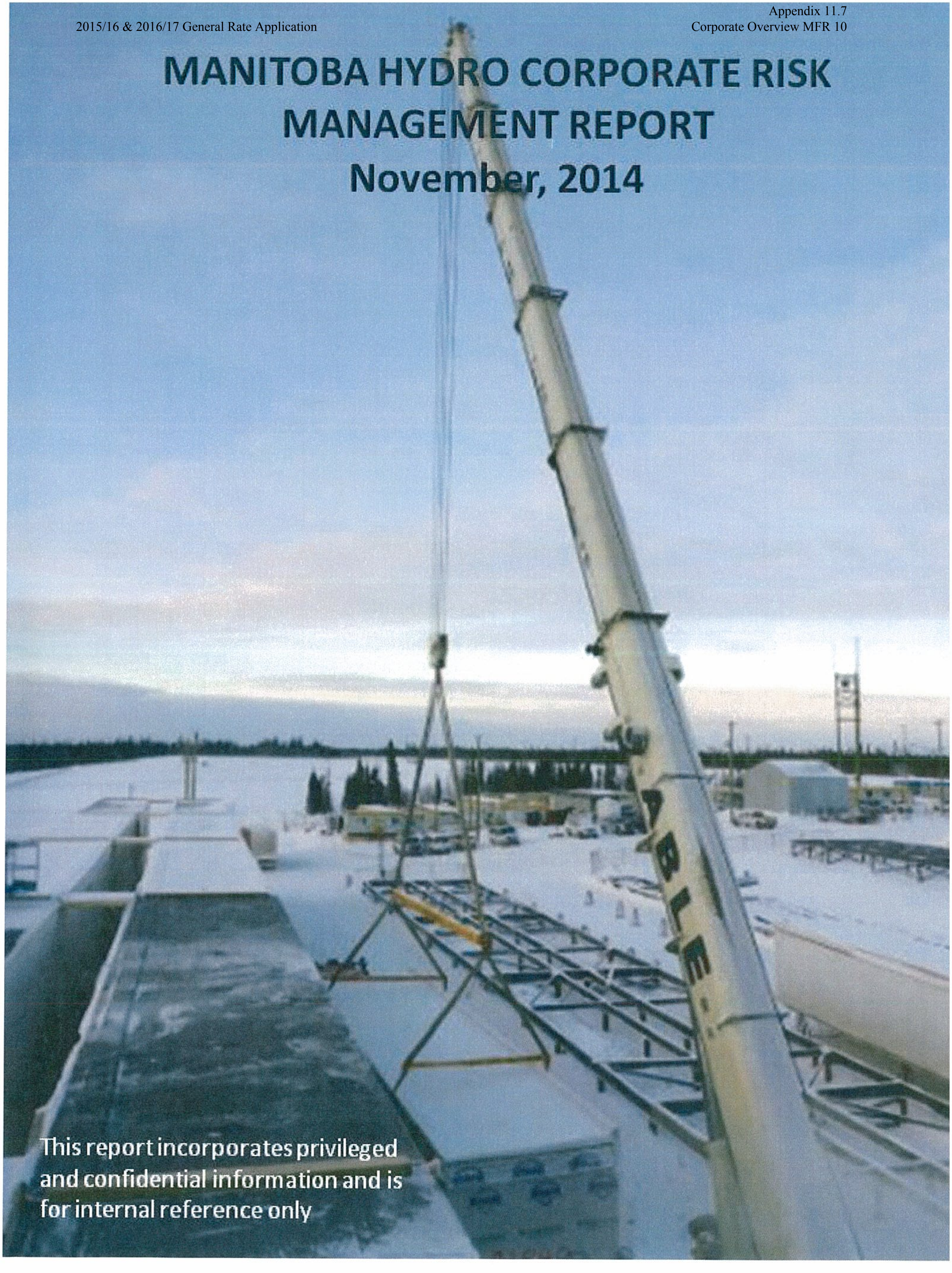
Corporate Risk Analysis Report and Specific Risk Management Plans for all Major Risks including Drought.

Please find attached the redacted version of Manitoba Hydro's Corporate Risk Management Report.

In addition, Manitoba Hydro has provided a full copy of its Corporate Risk Management Report to the PUB, in confidence, as requested in PUB/MH I-84b.

MANITOBA HYDRO CORPORATE RISK MANAGEMENT REPORT

November, 2014



This report incorporates privileged and confidential information and is for internal reference only

Cover: Keewatinohk Construction Camp
When completed the Keewatinohk Converter Station
will improve power reliability and expand
exporting capabilities.

TABLE OF CONTENTS

I. INTRODUCTION

The Corporate Risk Management Report is normally updated on an annual basis to provide Manitoba Hydro's stakeholders with information on the status of major risks facing the Corporation as it carries out its mandate. The report identifies and assesses each risk, describes activities used to manage the risk and provides estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided.

As a Crown-owned utility providing an essential and life-sustaining energy service to Manitobans, Manitoba Hydro has a relatively low tolerance for risk. However, because Manitoba Hydro is also an important economic driver for the Province, some risks are necessary in order to take advantage of opportunities to maximize value for stakeholders. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of:

- identifying threats that affect the achievement of the Corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on reducing the occurrence of negative events. However, the Corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, aging infrastructure maintenance and replacement, increasing regulatory, environmental and legal requirements, and accelerated technological change. Manitoba Hydro manages these risks through an integrated control framework and through the maintenance of an adequate level of retained earnings.

Manitoba Hydro's Corporate Risk Management Report is structured to provide the following:

- A summary of the high consequence risks including:
    - Loss of major infrastructure
    - Drought
    - Loss of export markets
- An overview of significant and emerging risks and actions taken to address those risks.
- A Corporate Risk Map providing a visual depiction of Manitoba Hydro's risks categorized into high, medium and low likelihood of occurrence and the corresponding consequences.
- A Corporate Risk Tolerance Assessment of each risk.
- Corporate Risk Profiles - one page summaries of each of Manitoba Hydro's risks.

II. HIGH CONSEQUENCE RISKS

The most significant risks facing Manitoba Hydro are those rated as high consequence due to the potential magnitude of impact on the Corporation's ability to achieve its mandate and strategic goals and are quantified in the following table:

RISK	POTENTIAL FINANCIAL IMPACT
INFRASTRUCTURE	
Prolonged loss of supply	> $2 billion
DROUGHT	
Water Supply Variation / Drought	>$1.7 billion for a 5 year drought commencing in 2017 (IFF 14)
LOSS OF EXPORT MARKET ACCESS	> 30 % of electricity revenue

Infrastructure Risk (Category D)

A catastrophic infrastructure failure continues to be the most significant risk facing the Corporation and its customers. Potential impacts include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. Failure can be caused by a number of factors including an extreme weather event, sabotage, fire, human error, or technical malfunction.

By the nature of its business, Manitoba Hydro has an especially low tolerance for infrastructure risk. Significant efforts are expended on managing this risk in a manner that avoids the occurrence of a catastrophic event and minimizing consequences should a catastrophic event occur.

Risk Treatment

In the short term, actions are continually being taken to enhance emergency response and disaster management processes. In the longer term, major investment in renewal and expansion of the infrastructure system are underway to maintain and improve system reliability, energy security and safety. Key management plans and projects include:

- Construction of Bipole III with a planned in-service date of 2018.
- Re-termination of the 500 kV Interconnection at Riel (2014).
- Renewal and replacement of aging electric and gas infrastructure over a long term period to improve system capacity and reliability. This includes critical distribution assets and stations, rehabilitation of existing generators, wood poles, cable and gas pipe replacement, cyber and physical security upgrades, and changes to gas distribution operations and pipelines to respond to changes in geographic gas production and shipment patterns. These changes to gas distribution operations also include lessons learned from a four day loss of gas supply to a large number of customers as a result of an explosion of the TransCanada main gas pipeline.
- Moving forward with implementation of Manitoba Hydro's Development Plan to meet export sales and forecasted domestic load growth. The provincial

government and Public Utilities Board endorsed proceeding with the Keeyask Generating Station, the new 500 kV line to Minnesota and increased levels of Demand Side Management activity. In addition to meeting domestic demand, these projects will allow the Corporation to increase firm export obligations and access greater amounts of energy with additional import capability provided by the new interconnection.

- Water retaining structures and flow control management, including: surveillance inspections, instrumentation monitoring, and engineering analyses of dams and dykes including emergency plans for individual facilities; systematic utilization of failure modes-based condition assessment techniques; and rehabilitation of the Pointe du Bois spillway facility.

- Continual improvement of the Corporate Emergency Management Program that includes a long term plan for managing the available resources, load and system supply following the loss of infrastructure; development of business continuity plans; constructing an emergency fuel depot; spare infrastructure material and equipment inventory to enable timely re-building and restoration of potentially affected assets. The corporation also has short term emergency energy and mutual aid agreements with Ontario, Saskatchewan and U.S. Utilities.

Water Supply Variation / Drought Risk (C.1 and D.2)

On average, there is a high likelihood of a drought occurring about once in every ten years. In the circumstances of an extreme drought that is more severe than the worst on record, there is a possibility of insufficient energy supplies being available to meet firm load demands. This would result in extreme financial and reputational impacts on the Corporation. The cost of a five year drought similar to the worst on record is estimated to be $1.7 billion (IFF 14) for a drought commencing in 2017.

Risk Treatment

There are several measures in place to manage the impacts of a drought, as follows:

- Manitoba Hydro's current generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. A drought more severe than the worst on record could occur and would require non-normal operations. This may include operating reservoirs outside of the normal range for power production. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation, or rotating reductions of non-essential load. Actions to manage drought will depend on its duration and severity and any other conditions that prevail at the time.

- Once built, the new interconnection with the U.S. in combination with additional long term exports in the Development Plan will provide the Corporation with increased ability to access additional amounts of energy through higher imports than planned and through financial settlement of firm export contracts.

- Adequate retained earnings are required to protect against a repeat of the worst drought on record. At March 31, 2014 retained earnings totaled $2.7 billion. It should be noted, however, that while drought is a major quantifiable risk, an adequate level of retained earnings is required to recover from other significant risks such as a prolonged loss of supply or the loss of export market access.

Export Market Access Risk (Category A.2)

On average Manitoba Hydro derives a significant portion of its revenue from export sales to U.S. and Canadian markets. The prime impact of restricted market access would be significantly reduced net export revenues which are fundamental in keeping domestic rates low and offsetting the upfront costs of capital investments. Market access risk also includes restrictions on Manitoba Hydro's ability to import which could increase the cost of droughts, and degrade system reliability.

Risk Treatment

Manitoba Hydro continues to actively work to mitigate and manage market access uncertainties, as follows:

- In alliance with other industry participants such as the Canadian Electricity Association, and other stakeholders, Manitoba Hydro continues to lobby MISO, IESO and FERC for the development or elimination of market rules that affect electricity trade and facilitate full participation of Manitoba Hydro in US and Canadian electricity markets.

- Manitoba Hydro also engages in extensive lobbying efforts in the US to promote waterpower as a clean, reliable and renewable source of energy and to counter anti-hydro special interest group lobbying.

- The Corporation also engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans.

- Market access risk is also reduced by having long term contracts and strong relationships in place with major export counterparties.

III. SIGNIFICANT AND EMERGING RISKS

While loss of infrastructure, drought and potential loss of export markets remain as the highest consequence risks for the Corporation, there are other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate. These are:

Infrastructure Investment (Category D / A.2.6)

Manitoba Hydro is moving forward with a number of major initiatives (e.g. construction of Bipole III, replacement of aging infrastructure, Keeyask generating station, a new interconnection to the U.S and increased Demand-Side Management activities) in order to further improve electrical and gas system reliability, meet the future energy needs of the province, and take advantage of export opportunities. These plans will require the investment of approximately $18 billion (CEF 14) over the next 10 years.

There are a number of risks associated with such large initiatives that will challenge the Corporation's ability to meet Manitoba's energy needs while keeping customer rates affordable, and maintaining the Corporation's financial strength. These challenges include managing the costs of Bipole III, Keeyask and the new interconnection project; [redacted] Mitigation measures to address these cost risks include the use of best practices in cost estimating, contracting practices, the inclusion of appropriate contingencies and management reserves. [redacted]

With regard to Conawapa, the Corporation has suspended the majority of expenditures associated with that project consistent with government direction following the PUB's NFAT report. Conawapa is now seen as an opportunity that will only proceed if sufficient additional profitable export sales materialize that will shoulder most of the financial risk associated with building Conawapa much earlier than needed for domestic purposes. Without those contracts further expenditures to protect an early in-service date for Conawapa will not be made. The consequences of that will be a lost opportunity resulting in higher rates in the very long term, reduced near term provincial economic activity and reduced socio-economic benefits to northern aboriginal communities who would partner with Manitoba Hydro on the project.

Financial Strength (B.7)

Maintaining financial strength is essential in order to make the necessary investments in infrastructure, to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in the Corporation's operations and to provide customers with long-term rate stability and predictability and avoid the need for large or sudden rate increases in the future. The required investment in new and existing infrastructure is expected to place a certain degree of pressure on the Corporation's key financial targets, and if not carefully managed, there is a risk of higher required future rate increases or potential negative impacts to the credit rating of the Province.

Key areas of focus to maintain financial strength include:

- Continuing cost containment measures. This includes utilizing resources effectively and efficiently while diligently managing capital projects to be on time and on budget. Management continues to evaluate the need to fill positions vacated as a result of attrition, considering opportunities for process improvement, technological enhancements and organizational restructuring. This also involves leveraging experience from the development of new tools and past projects to improve upon capital cost estimating, project and contract management.
- Aggressively pursuing a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

- Managing and mitigating financial risk by closely monitoring economic factors, financial markets, and energy markets.
- Implementing modest, regular domestic electricity rate increases necessary to achieve financial targets over the long term.

Domestic Electricity Rate Increases (B.7)

The infrastructure system that served Manitoba well for decades now needs significant re-investment to continue meeting the province's needs. Electricity rates in Manitoba must rise to ensure the ongoing safety and reliability of the electricity supply and delivery system. This is an issue that is present across North America, as other utilities address aging infrastructure and growing demand.

Manitoba's electricity rates continue to be among the lowest overall in North America, due in large part to past investments in hydroelectric generating stations and the contribution to earnings from the sales of surplus energy into the export market. However, Manitoba Hydro's plan for re-powering the province requires a significant capital investment. This investment in the replacement and refurbishment of plant will require increased revenues, which must be obtained from a series of future electricity rate increases, at levels higher than the historical average.

It is a significant challenge to convince stakeholders that higher rate increases are in the best long-term interests of all ratepayers to ensure ongoing safe and reliable service. Significant efforts will need to be focused on delivering compelling and convincing arguments before the PUB to obtain the required level of rate increases going into the future. Even with the projected rate increases, it is expected that Manitoba Hydro's domestic customers will continue to have electricity rates that are affordable and competitive.

Offering new and expanded Power Smart programs aggressively targeting additional electricity and natural gas savings, as outlined in the Corporation's development plan, will aid customers in managing their overall energy costs.

Export Sales (Category A.2)

As was previously mentioned, increased export sales are fundamental to achieving the Corporation's strategy of reducing the costs of building new generation supply for Manitoba ratepayers.

Key factors affecting the ability to increase export volumes and revenues are:

- **Export Market Prices -** In recent years export prices for electricity have been affected by the economic slowdown in the U.S. and the availability of low-cost natural gas made possible by new production techniques. The corporation has endeavored to reflect these factors as accurately as possible in its forecasts of future export market prices. Based on the input of external industry specialists, the corporation is forecasting a moderate rise in export prices over the long term, restrained by the continued impact of natural gas pricing. There is a residual risk that export prices could be lower than industry experts are predicting, and that would be a downside risk that could hamper the Corporation's ability to achieve forecasted export revenues and other financial targets with projected rate increases.

- **Cost of New Hydraulic Generation** – The resources in the Corporation's development plan are supported by a number of export agreements, including a 250-megawatt sale to Minnesota Power, a 125 MW sale to Northern States Power and a 108–megawatt sale to Wisconsin Public Service. [redacted]

  Commencement of construction of Conawapa is not required in the near term to serve Manitoba load. As a result resumption of planning and capital expenditures for Conawapa will only proceed if sufficient firm export interest materializes in the next two years that convince the Corporation that there are significant benefits with proceeding and that the risks of the project will not be borne by Manitoba ratepayers. To date only the 308 MW Power Sale Agreement with Wisconsin

Public Service has been signed. By itself that sale only requires 30% of Conawapa's output until 2035. Commitments tied to a large portion of its remaining output will be necessary before resumption of expenditures can be justified.

- **Market Access -** Manitoba Hydro's development plan includes the construction of a new 500 kV interconnection with the U.S. The interconnection will increase export capability by 883 MW and import capability by 683 MW. These increases in transfer capability will increase the amount of firm load that can be served by the Manitoba generating system, will enhance the value of new DSM initiatives and will result in Manitoba Hydro achieving higher export prices and lower import prices. The line will increase export volumes by reducing water spillage in high water years.

  Critical to receiving regulatory and political approval to build the US portion of the interconnection is having a US utility who will champion and build the line in the US. The risks of this project not moving forward are significantly reduced this year as Manitoba Hydro and Minnesota Power have now signed several agreements which establish the business arrangements necessary for the Minnesota Power to proceed with the permitting, and route selection processes. These permitting processes are underway and MP expects to receive approval by the end of 2015 with actual construction of the Great Northern Transmission Line commencing in 2016.

  In addition, Manitoba Hydro's subsidiary (6600271 MB. Ltd), Minnesota Power and MISO have signed a Facilities Construction Agreement. These agreements are subject to several conditions and regulatory approvals which still must be satisfied before construction can commence.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Gas Price Volatility (B.5)

There is significant upward cost pressure for transportation services on the TCPL Canadian Mainline (the "Mainline"), to which Centra is currently captive in bringing natural gas to its load centre. The Mainline is significantly underutilized resulting in less revenue than that which is required to cover the Mainline's relatively high embedded cost structure. As a result, the pipeline has been seeking regular toll increases since 2010, which costs are passed through to Manitoba natural gas ratepayers. Tolls on the Mainline also affect transportation services that Centra obtains from third parties.

This market circumstance was recently compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post-2020 between the under-utilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle, which would facilitate the avoidance of cost responsibility for under-utilized or stranded assets on the Mainline by eastern shippers at the expense of Centra and other captive shippers on the Western Mainline. Centra is the largest captive shipper on the Western

Mainline. The proposal, if approved by the National Energy Board ("NEB"), is expected to result in significantly higher costs and risk for Centra than it would bear if the Mainline were to remain integrated.

Centra actively intervened to oppose Mainline segmentation in the recent Oral Hearing RH-001-2014 before the NEB regarding the Application by TCPL for Approval of Mainline 2015-2030 Tolls & Restructuring. Interested parties are awaiting a Decision by the NEB, which is expected in November, 2014. In the event that the Decision is unfavourable for Centra, work will be undertaken to explore alternatives to continuing to move gas on the Mainline.

Interest Rates (B.2)

As a result of the intensive capital investment period, it is projected that Manitoba Hydro's level of debt will significantly increase and financial results will be affected by market interest rates. Over the next 10 years the potential cumulative financial impact of a one-percent change in interest rates is estimated at $1.1 billion (IFF 14).

Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of short term debt, floating rate debt and debt to be refinanced within the subsequent 12 month period to a maximum of 35% of the total debt portfolio. When selecting terms for its new borrowings, Manitoba Hydro gives careful consideration to the debt maturity schedule and the total level of annual financing requirements. The debt management strategy guidance is to have less than 15% of the long term debt portfolio maturing within a fiscal year. In order to mitigate refinancing risk, to maintain financing flexibility during the intensive capital investment period, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term financings with maturities of 10+ years, while maintaining short term debt and floating rate long term debt within policy limits.

As a result of the low interest rate environment over the past several years Manitoba Hydro has been able to reduce its net weighted average interest rate by approximately 2.0% since 2006/07 and increase its weighted average term to maturity by over three years during the same period.

Environmental (Category C)

There are a number of environmental issues currently facing the Corporation that could impact operations if they are not addressed.

A potentially significant environmental issue arises as a result of the 2013 Clean Environment Commission (CEC) recommendation to have both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licensed for construction. [redacted] Manitoba Hydro has completed Phase I of the Study and submitted it to the government. Phase II is now underway and a new committee has been formed with the Province.

Another significant environmental issue deals with the listing of Lake Sturgeon under the Species at Risk Act (SARA). Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found and it is likely that at most sites the infrastructure and operations have negatively affected the fish and/or its habitat. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing [redacted] Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under SARA at most locations in Manitoba. If Lake Sturgeon is listed as "Endangered" under the SARA, the Corporation could face restrictions on current operations, structural modifications to infrastructure, delays in developing new generation due to difficulties with securing permits, and high costs of recovery measures that are potentially mandated. There is also a remote chance that new projects could be cancelled. The Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA, however uncertainty remains.

Regulation and Licensing (H.1)

The Corporation requires a variety of regulatory approvals and licenses to carry out its activities. Key approvals and licenses include the National Energy Board, water power and environmental approvals to build new generation or transmission facilities or to maintain or improve the efficiency of existing facilities. Failure to obtain approvals and licenses on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts. These could result in increased costs, reduced hydraulic generation, capacity and export sales. Expiration of a license without renewal could expose the Corporation to embarrassment and loss of reputation and cancelation of a license could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and Manitoba Hydro would lose the asset and associated capacity and generation.

There are several measures in place to manage these risks. These include:

- Incorporating regulatory/licensing concerns into the planning of new rate programs and facilities (e.g. low-head Wuskwatim to minimize environmental impact).

- Pursuing regulatory/license approvals with appropriate diligence and explaining the merits of the corporate position at any public proceedings where the scope of regulation is under debate.

- Maintaining systems to ensure ongoing compliance with regulatory/license requirements and focusing attention on overall corporate image.

- Making recommendations for an efficient and streamlined regulatory framework.

- With respect to Water Power Licenses: (1) Manitoba Hydro has a strong working relationship with the WPA Licensing Section at Water Stewardship. This ensures proper understanding of licensing condition implications and to ensure timely licensing activities; (2) Manitoba Hydro monitors compliance with its WPA licenses and self reports annually on compliance; (3) Manitoba Hydro applies for short term license extensions when licenses would otherwise expire. Historically Manitoba Hydro had several WPA licenses that had expired. Although this was a potential source of embarrassment, it did not result in a disruption of operations; and (4) Manitoba Hydro operates its facilities within the limits established in the WPA licenses. To the extent that deviations are necessary or occur, authorization is requested when possible from Water Stewardship. As a result there is no risk of license cancelation as a result of non-compliance.

Workforce (Category E)

Attracting, developing and retaining a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to the Corporation's success. Key factors that impact the ability to achieve this are the number of employees that are eligible for retirement, competition for highly skilled workers, and the ability to keep up with technological and other changes. Manitoba Hydro's contractors will also be impacted by the same competition.

The Corporation is looking at the demographic shift that is occurring in its workforce as a challenge as well as an opportunity. Nearly 900 employees are eligible for retirement in 2014. With years of accumulated experience and knowledge, many of those nearing retirement age are key contributors to the Corporation's success. It is important therefore that appropriate succession planning, recruitment and retention activities are in place to maintain safe and reliable service and to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors. At the same time there is opportunity to achieve efficiencies and cost reductions by evaluating the need for positions that are vacated.

Infectious Disease – Ebola Virus (E.1.1)

In June 2014 an outbreak of the Ebola virus occurred in West Africa that could potentially impact Manitoba Hydro operations if the virus is not contained. A number of Hydro employees seconded to the subsidiary company Manitoba Hydro International, as well as several MHI Independent contractors, were working in West Africa during the time of this outbreak and were relocated to various other countries in order to continue their work remotely. None were affected by this virus and they will not return to the area until such time that it is considered safe.

As is the case with any infectious disease, the Corporation needs to be ready and respond appropriately to the events as they occur. The developing and changing nature of this Ebola crisis is being assessed and any changes to established practices and/or policies will be performed to meet the declared requirements of the health authorities. A communication strategy to employees is also under development.

Cyber Security (F.2.1)

The growth of electronic communication and automation, while delivering significant benefits to Manitoba Hydro, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro Information and Operational Technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target. These cyber attacks could have a significant impact on Manitoba Hydro operationally and financially, and may have a rippling effect on the Manitoba economy.

Countermeasures, management controls and processes are in place to mitigate this risk. The corporation is also developing a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Steps to address the recommendations include establishing an Enterprise Security Council comprised of senior executives to provide oversight for all physical and technology security. The Auditor General's report consisted of eight recommendations and the Corporation has developed action plans to address each.

Reputation (G.1)

The Corporation has recently completed a number of significant regulatory hearings, including the Clean Environment Commission and Needs For and Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan. [redacted] Similar to other Canadian electric utilities, the Corporation's customer satisfaction ratings have been recently declining below its typical range.

A Public Communication Plan continues to be developed to aid in managing customer perceptions of the Corporation's efforts to meet their mandate as outlined under the Manitoba Hydro Act while balancing the need for future domestic rate increases. A component of the plan will use the Corporation's existing communications channels, stakeholder engagement and media relations efforts to address issues that may continue to arise. [redacted]

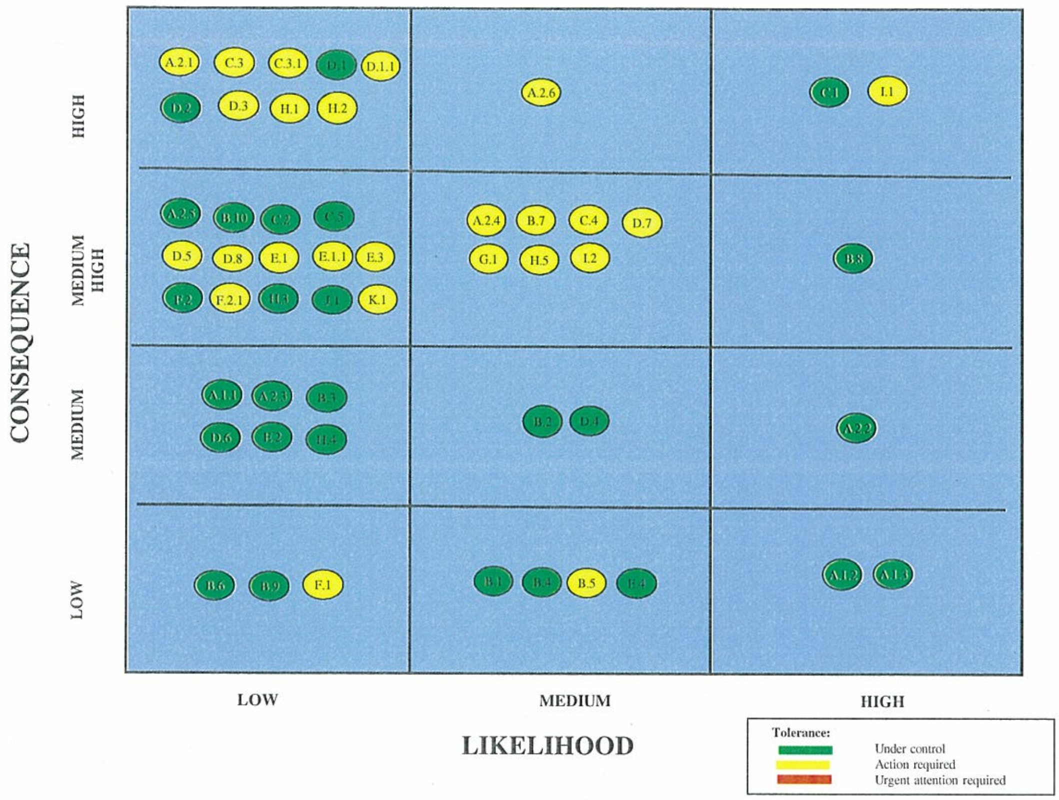
[redacted] The Corporation will take all steps possible to try to ensure that its customer satisfaction rating and current positive reputation are maintained.

IV. CORPORATE RISK MAP

Corporate Risk Profiles (see Appendix B) identify and assess each risk facing the Corporation, describe activities used to manage the risk, and provide estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided. The risk rating and tolerance criteria are provided in Appendix C. As well, further detail of the risk tolerance assessment for each risk is provided in Appendix A.

The following Corporate Risk Map illustrates the results of a residual risk assessment for all risks facing the Corporation.

CORPORATE RISK MAP



A. Market
1. Domestic
   1. Competition
   2. Uneconomic Loads
   3. Load Growth Uncertainty
2. Export
   1. Regulatory Environment
   2. Long Term Price Uncertainty
   3. Transmission
   4. Special Interest Groups
   5. Protectionism
   6. Major Export Contracts Requiring Early Conawapa ISD

B. Financial
1. Exchange
2. Interest Rates
3. Credit
4. Inflation
5. Gas Price Volatility
6. Gas Derivative Instruments
7. Financial Targets
8. Energy / Fuel Price Volatility
9. Power Financial Instruments
10. Liquidity

C. Environmental
1. Water Supply Variation / Drought
2. Climate Change
3. Operational Impact and Infrastructure
   1. Legal - Species at Risk Act
4. Reliability of Supply
5. Upstream Regulation and Water Withdrawals

D. Infrastructure
1. Loss of Plant (all property, all perils)
1.1. Water Retaining Structures and Flow Control
2. Extreme Drought – Shortfall Energy
3. Prolonged Loss of System Supply
4. System Shutdown (Short Term)
5. System Shutdown (Natural Gas)
6. Technology
7. Special Interest Groups
8. Emergency Management Program

E. Human
1. Safety and Health
   1. Infectious Disease
2. Union / Employee Issues
3. Workforce
4. Technology

F. Business Operational
1. Supply Chain
2. Operational Controls
   1. Cyber Security

G. Reputation
1. Reputation

H. Governance / Regulatory / Legal
1. Regulation and Licensing
2. Export Market Access
3. Legal Compliance
4. Contracts and Ventures
5. NERC/MRO Reliability Standards

[redacted]

J. Emerging Energy Technologies
1. Emerging Energy Technologies

K. Strategic
1. Strategic Direction and Implementation

Risks that are coded yellow on the risk map indicate that some emerging issues need to be monitored and additional action may be required. A summary of the yellow coded risks that are not discussed in the previous sections of this report is provided below.

- [redacted] **A.2.1 Export Regulatory Environment –** Export market rules continually evolve with new rules being imposed that could impact future access to export markets. [redacted]

  [redacted]

  [redacted]

  Manitoba Hydro collectively manages its market access risks through a comprehensive set of activities to monitor and address any potential threats to market access.

- **A.2.4 Export Special Interest Groups –** A positive corporate and product image enables the Corporation to maximize export sales opportunities and to develop generation and transmission projects required for both domestic needs and exports. Negative lobbying efforts by Special Interest Groups can tarnish the Corporation's image or the image of hydropower, limiting its marketability. Manitoba Hydro is managing this risk by: (1) Continuing to promote waterpower as clean, reliable and a renewable source of electricity; (2) Aggressively countering Special Interest Group activities with Manitoba Hydro's perspective; and (3) Expanding engagement with groups who may lobby for or against Manitoba Hydro.

- **A.2.6 Major Export Contracts Requiring Early Conawapa ISD -** There is a lost opportunity to Manitoba Hydro if it's export customers do not commit to additional large power sales agreements [redacted] These new agreements will justify an early in-service date for Conawapa, otherwise spending on Conawapa will end.

  Several actions are being taken to manage this risk, including: (1) Aggressively pursuing discussions with export customers to ensure that they understand that their [redacted] commitment is required if they are counting on purchasing generation from Conawapa, and (2) Advocating with US legislative and regulatory bodies to provide incentives for US utilities to contract for new hydro from Manitoba as part of their plans to address emerging carbon regulations and generation retirements.

- **C.4 Reliability of Supply –** The Corporation is at risk that environmental licensing concerns could obstruct the Corporation's ability to build the necessary transmission facilities required to provide a reliable supply of energy. The Corporation will continue to be proactive in addressing these concerns and ensuring adequate lead times to resolve issues.

- **D.1.1 Water Retaining Structures and Flow Control** – Dam or dyke structures can fail resulting in impacts ranging from insignificant to catastrophic. [redacted]

- **D.7 Special Interest Groups –** [redacted]

- **D.8 Emergency Management Program -** As discussed throughout the Category D Infrastructure section, the Corporation's energy infrastructure is highly exposed to events that can have impacts ranging from insignificant to catastrophic. These include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. To ensure that appropriate plans and programs are in place, there are: (1) policies and procedures to guide actions, (2) staff training and emergency preparedness exercises on a regular basis, (3) actions to follow up on and address identified deficiencies, and (4) continual enhancements to the program to ensure the state of readiness. Initiatives currently underway include developing a corporate plan for business continuity for continuation of critical operations and constructing an emergency fuel depot. Several other initiatives are being considered.

- **E.1 Safety and Health** – Employee safety is always a key concern to the Corporation due to the inherent nature of the operational work performed by Manitoba Hydro. To date a focus on continuous safety improvements has resulted in a steady decline in workplace accident severity and frequency rates. The Corporation will continue to focus on making improvements to the safety program.

- **F.1 Supply Chain** – The Corporation requires a variety of critical goods and services to achieve its objectives. [redacted]

- **H.5 NERC/MRO Reliability Standards** – Achieving the highest level of reliability is one of the core tenets of Manitoba Hydro's Vision statement. In support of this vision, Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC) and has been legally required to comply with nearly 100 of its reliability standards since 2007. These standards specify requirements for planning, operating and maintaining the bulk electric system. The Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance.

- **K.1 Strategic Direction and Implementation** – Manitoba Hydro continues to be at a critical point in renewing and expanding Manitoba's electrical and gas system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes. Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

Financial Information MFR 2

Summary of Reasons for Application Table of operating results (Tables 2.1.1, 2.1.2 2010 GRA) including ten years of record/ (7 years actual and current and test years) including the retained earnings for electric operations, and the financial targets, interest coverage, capital coverage and debt to equity ratio for electric operations only.

Please see the following tables for the requested information.

Net Income - Electricity Operations

	Actual							Forecast		
(in millions of $)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Revenue										
General Consumers Revenue										
- at approved rates	$ 1 075	$ 1 127	$ 1 145	$ 1 200	$ 1 193	$ 1 341	$ 1 424	$ 1 437	$ 1 454	$ 1 460
- Bipole III Reserve	-	-	-	-	-	-	(19)	(30)	(32)	(34)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	366	323	202	172	98	101	137	150	181	147
Other Revenue	8	16	6	6	14	30	22	15	14	14
	1 448	1 466	1 353	1 379	1 305	1 472	1 564	1 572	1 617	1 587
Expenses	1 112	1 209	1 193	1 240	1 243	1 407	1 439	1 495	1 571	1 653
Operating, Maintenance and Administrative	323	364	378	397	412	463	481	486	542	552
Finance Expense	401	433	373	388	385	452	435	495	510	548
Depreciation and Amortization	324	340	358	365	353	392	411	405	401	422
Capital and Other Taxes	57	64	76	81	83	86	97	99	107	121
Corporate Allocation	8	8	8	9	9	9	9	9	8	8
Other expenses	-	-	-	-	1	5	6	2	2	2
Non-controlling Interest	-	-	-	-	-	13	22	25	12	8
Net Income (loss) before proposed rate increases	$ 337	$ 257	$ 160	$ 139	$ 61	$ 78	$ 147	$ 102	$ 58	$ (58)
Proposed rate increases (3.95% April 1, 2015 and 3.95% April 1, 2016)									57	118
Net Income including proposed rate increases	$ 337	$ 257	$ 160	$ 139	$ 61	$ 78	$ 147	$ 102	$ 115	$ 59

Retained Earnings and Financial Ratios (without proposed rate increases)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 1 784	$ 2 028	$ 2 190	$ 2 328	$ 2 390	$ 2 468	$ 2 614	$ 2 717	$ 2 721	$ 2 662
Debt to Equity Ratio (electric operations)	73:27	77:23	72:28	72:28	74:26	75:25	77:23	78:22	82:18	85:15
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.13	1.25	1.16	1.08	0.93
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.26	1.39	0.98	0.92	0.74

Retained Earnings and Financial Ratios (including proposed rate increases)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 1 784	$ 2 028	$ 2 190	$ 2 328	$ 2 390	$ 2 468	$ 2 614	$ 2 717	$ 2 778	$ 2 837
Debt to Equity Ratio (electric operations)	73:27	77:23	72:28	72:28	74:26	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.13	1.25	1.16	1.16	1.07
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.26	1.39	0.98	1.02	0.94

Comparison of Electrical Operations MH14 to MH13
Increase/(Decrease)
(millions of $)

	2015			2016			2017		
	MH14	MH13	Variance	MH14	MH13	Variance	MH14	MH13	Variance
General Consumers at projected rates	1 407	1 442	(35)	1 479	1 516	(36)	1 544	1 592	(48)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	150	118	32	181	77	104	147	90	57
Other	15	13	2	14	13	1	14	14	0
Total Revenues	1 572	1 573	(1)	1 674	1 606	69	1 705	1 695	9
Operating and Administrative	486	494	(8)	542	542	(0)	552	548	4
Finance Expense	495	499	(4)	510	514	(3)	548	567	(19)
Depreciation and Amortization	405	440	(35)	401	437	(36)	422	448	(26)
Capital and Other Taxes	99	101	(2)	107	109	(2)	121	121	(0)
Corporate Allocation	9	9	(0)	8	9	(0)	8	9	(0)
Other Expenses	2	0	2	2	0	2	2	0	2
	1 495	1 543	(47)	1 571	1 611	(40)	1 653	1 692	(39)
Non-controlling Interest	25	24	1	12	18	(6)	8	16	(8)
Net Income	102	55	48	115	12	103	59	19	41

Financial Information MFR 3

For the years 1999/00 through the test years, a details of rate increases requested, approved, the annual revenue increase and prevailing Manitoba CPI in similar basis to PUB/MH 1-2 (b) (2010 GRA).

Please see the table below.

	% Rate Inc Req.	% Approved	Annual $ Inc./(Dec.)	Inflation Rate
1999/00	0%	-	-	2.2%
2000/01	0%	-	-	2.5%
2001/02	-1.92% Uniform Rate Legislation	-	($14.4) million	2.1%
2002/03	0%	-	-	2.3%
2003/04	0% Status Update	-0.72% Apr 1/03 BO 7/03	($6.5) million	0.9%
2004/05	3.0% Apr 1/04 (two year application)	5% Aug 1/04 Plus conditional 2.25% Apr 1/05 & 2.25% Oct 1/05 BO 101/04 & 143/04	$32.3 million	2.7%
2005/06	2.5% Apr 1/05	2.25% BO 34/05	$21.8 million	2.4%
2006/07	2.25% Feb 1/07	2.25% Mar 1/07 BO 20/07 (interim) BO 90/08 (final)	$23.1 million	2.0%
2007/08	0%	0%	-	1.9%
2008/09	2.9% Apr 1/08	5.0% Jul 1/08 (except ARL 0%) Plus conditional 4.0% Apr 1/09 BO 90/08 (final)	$52.4 million	2.2%
2009/10	3.9% Apr 1/09	2.9% Apr 1/09 BO 32/09 (final)	$32.8 million	0.6%
2010/11	2.9% Apr 1/10	2.9% Apr 1/10	$32.9	1.0%

	% Rate Inc Req.	% Approved	Annual $ Inc./(Dec.)	Inflation Rate
		(except ARL 0%) BO 18/10 (interim) BO 5/12 reduced increase to 1.9%. Review & Vary BO 43/13 approved original increase of 2.9% (final)	million	
2011/12	2.9% Apr 1/11	2.0% Apr 1/11 (except ARL 0%) BO 40/11 (interim) BO 5/12 & BO 43/13(final)	$24.4 million	2.8%
2011/12	0.9% Aug 1/11	0% BO 99/11 (interim) BO 5/12 (final)		
2012/13	3.5% Apr 1/12 2.5% Sep 1/12	2.0% Apr 1/12 BO 32/12 (interim) BO 43/13 (final) 2.4% Sep 1/12 BO 116/12 (interim) BO 43/13 (final)	$25.8 million $31.0 million	1.6%
2013/14	3.5% Apr 1/13	3.5% May 1/13 (1.5% to BPIII Reserve) BO 43/13 (final)	$47.6 million	2.4%
2014/15	3.95% April 1/14	2.75% May 1/14 (0.75% to BPIII Reserve) BO 49/14 (interim) BO 51/14 (final)	$38.7 million	1.8% (est)
2015/16	3.95% April 1/15 (Proposed)		$57.4 million	1.9% (est)
2016/17	3.95% April 1/16 (Proposed)		$59.9 million	2.0% (est)

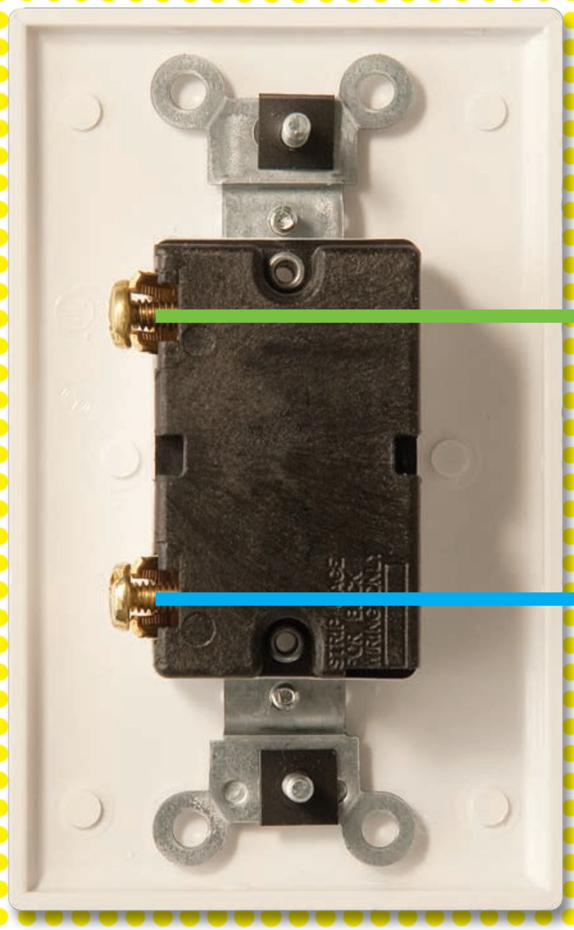
Manitoba Hydro

Manitoba Hydro-Electric Board

62nd Annual Report

For the Year Ended March 31, 2013

It starts with the flick of a switch.



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July 31, 2013

Honourable Dave Chomiak
Minister charged with the administration of the Manitoba Hydro Act
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Minister:

I have the honour of presenting the 62nd Annual Report of The Manitoba Hydro-Electric Board, together with the financial statements, for the fiscal year ended March 31, 2013.

Respectfully submitted,

William C. Fraser, FCA
Chair, The Manitoba Hydro-Electric Board

Millions of times a day our customers turn to us for the electricity they depend on.

CORPORATE PROFILE

Manitoba Hydro is one of the largest integrated electricity and natural gas distribution utilities in Canada. We provide reliable, affordable energy to customers throughout Manitoba and trade electricity within three wholesale markets in the Midwestern United States and Canada. We are also a leader in promoting conservation, providing numerous Power Smart* programs to help our customers get the most out of their energy. Nearly all of the electricity Manitoba Hydro produces each year is clean, renewable power generated using the province's abundant water resources.

Manitoba Hydro is a provincial Crown Corporation governed by the Manitoba Hydro-Electric Board, whose members are appointed by the Lieutenant-Governor in Council.

And, for over 60 years, Manitoba Hydro has answered that call.

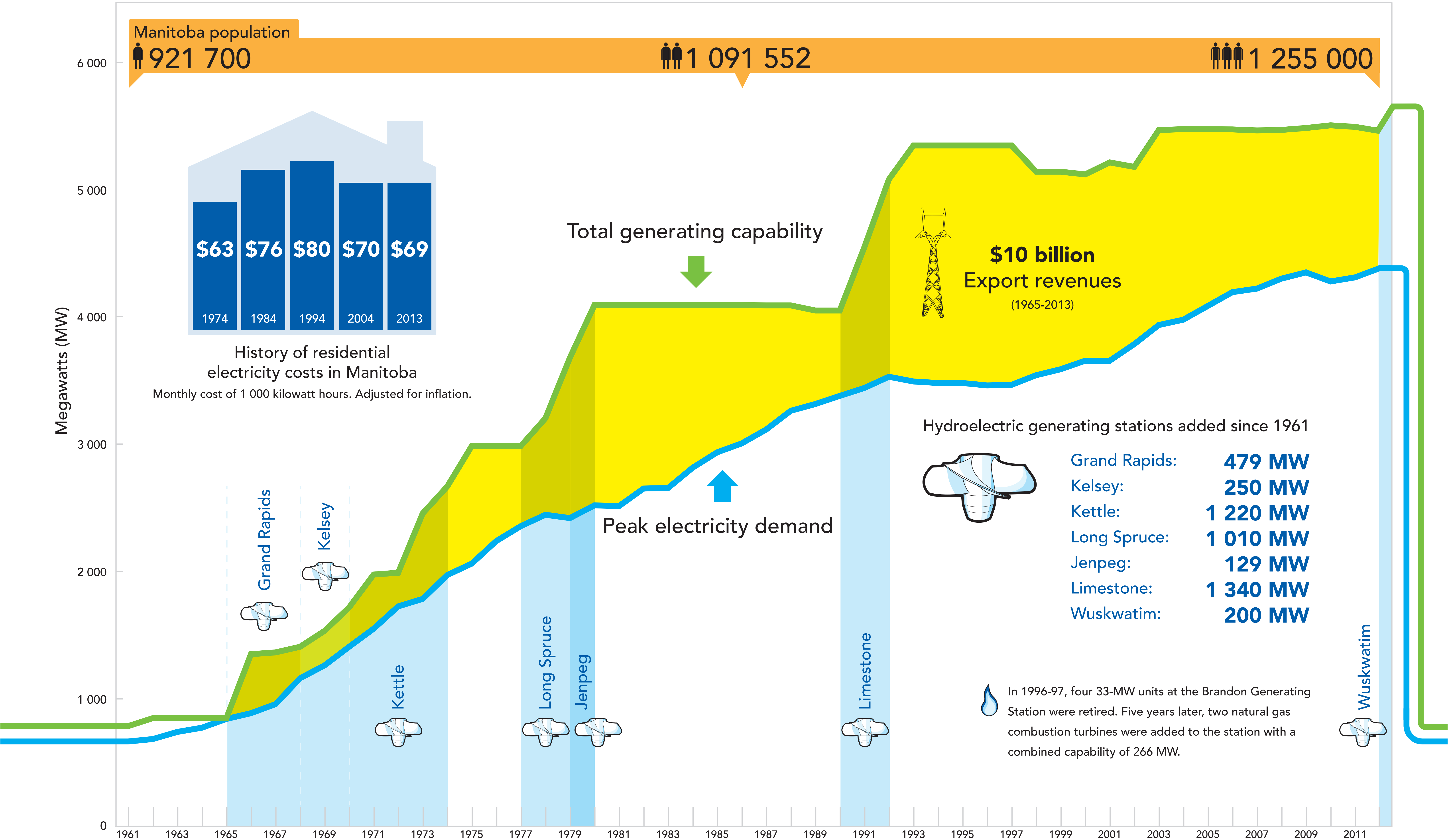
*Manitoba Hydro is a licensee of the Trademark and Official Mark.

We harnessed the energy flowing in this province's rivers; first building generating stations on the Winnipeg River and, as demand grew, moving north to the Saskatchewan and Nelson rivers.

We built the transmission and distribution systems to deliver that electricity.

We created transmission interconnections with other markets and sold our surplus electricity, bringing billions of dollars into Manitoba.

These investments resulted in one of the most affordable, reliable and sustainable power systems anywhere.


Manitoba population
921 700
1 091 552
1 255 000
Megawatts (MW)
6 000
5 000
4 000
3 000
2 000
1 000
0
$63
$76
$80
$70
$69
1974
1984
1994
2004
2013
History of residential electricity costs in Manitoba
Monthly cost of 1 000 kilowatt hours. Adjusted for inflation.
Total generating capability
Peak electricity demand
$10 billion
Export revenues
(1965-2013)
Hydroelectric generating stations added since 1961
Grand Rapids: 479 MW
Kelsey: 250 MW
Kettle: 1 220 MW
Long Spruce: 1 010 MW
Jenpeg: 129 MW
Limestone: 1 340 MW
Wuskwatim: 200 MW
In 1996-97, four 33-MW units at the Brandon Generating Station were retired. Five years later, two natural gas combustion turbines were added to the station with a combined capability of 266 MW.
Grand Rapids
Kelsey
Kettle
Long Spruce
Jenpeg
Limestone
Wuskwatim
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011

Now, it's time to invest in our system again.

The demand for electricity is continuing to grow here in Manitoba. New sources of energy are needed.

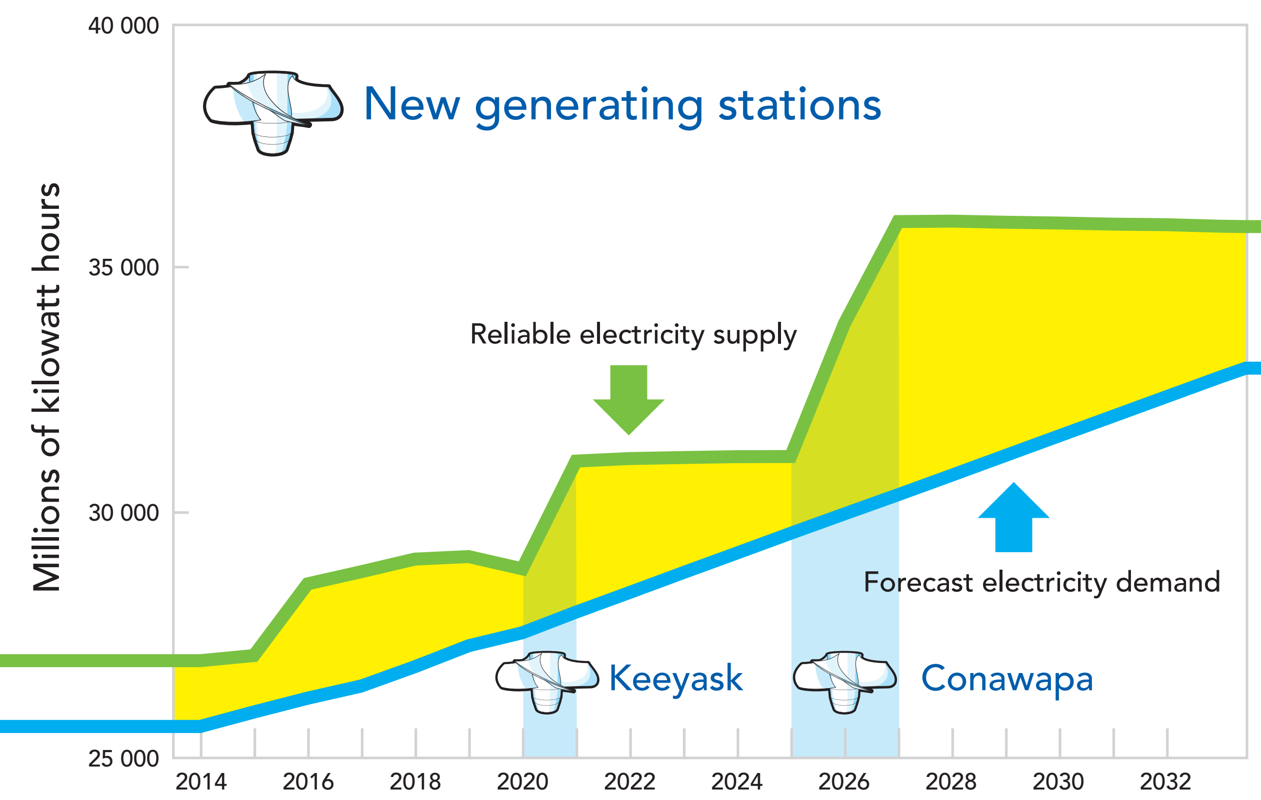
A considerable portion of the infrastructure we use to generate and deliver electricity is approaching the end of its service life and cannot continue to meet our customers' evolving expectations. To serve the future energy needs of this province, we need to renew, upgrade and construct new facilities.

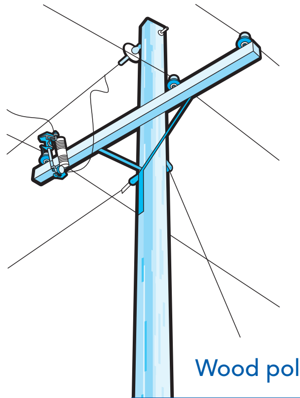
Manitoba Hydro is ready to meet these challenges.

Our plan continues the proven strategy of developing this province's clean, renewable hydro resources and building interconnections to leverage the associated export sale opportunities while enhancing reliability.

We are preparing to build the 695-megawatt Keeyask Generating Station and the proposed 1 485-megawatt Conawapa Generating Station along with a new transmission interconnection to the United States.

We are continuing to make investments in Power Smart energy conservation programs that will reduce growth in demand by over 500 megawatts in the next 15 years.

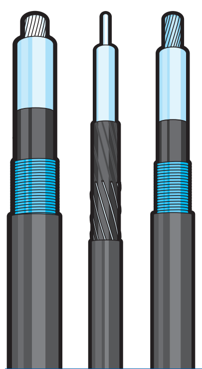




Wood poles in Manitoba Hydro's system: over 1 million

Poles that will need to be replaced in the next 20 years: **117 000**

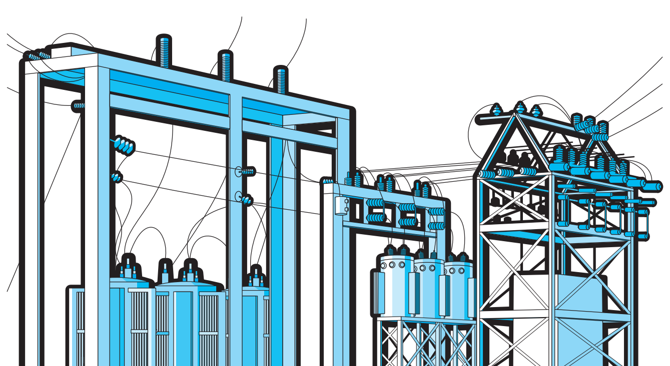
Estimated cost: **$400 million** (All costs in 2012 dollars.)



Underground distribution cable in system: approximately 6 100 kilometres

Percentage that will reach end of life in next 20 years: **55 percent**

Estimated cost to replace or refurbish: **$900 million**



Substations in Winnipeg: 97

Substations replaced/refurbished in next 12 years: **20**

Estimated cost = **$630 million**

2014 2016 2018 2020 2022 2024 2026 2028 2030 2032

We are accelerating investment in our infrastructure to maintain reliability; building the new Bipole III high voltage direct current transmission line and replacing assets — ranging from wood poles to substations — that have reached the end of their service life or the limits of their capacity.

We are investing in a powerful future for Manitoba, ensuring the next generation will continue to enjoy the benefits of affordable, reliable and sustainable electricity — every time they flick a switch.

Chair's message

Manitoba Hydro plays an important role in ensuring all Manitobans benefit from this province's energy resources. It was true nearly 50 years ago when the decision was made to develop the hydro potential of this province's northern rivers. It is true today as the corporation again turns north to develop new generating stations and transmission capacity.

These are important investments for Manitoba Hydro and the board carefully monitors all major projects. This includes engaging management of the corporation to review activities related to the planned development of the Keeyask and Conawapa generating stations and a new transmission interconnection to the United States.

In July, I had the opportunity to visit the new Wuskwatim Generating Station with leaders of the Nisichawayasihk Cree Nation (NCN) to mark the start of electricity production. Developed in partnership with NCN, Wuskwatim is a model of responsible resource development — one where potentially impacted Aboriginal communities are engaged in project planning, environmental assessments and in the creation of employment and business opportunities.

This responsible approach is also being taken with the planned Keeyask Generating Station which, pending regulatory approvals, will be developed in partnership with Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. The board was pleased with the progress on the project in 2012-13, which included filing its environmental impact statement.

Progress also continued on the Conawapa Generating Station, including the ongoing planning process with the communities in the vicinity of the project — Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, War Lake First Nation and Shamattawa First Nation.

A public hearing to review the environmental impact statement for the Bipole III Transmission Project concluded in the past fiscal year. It is anticipated that a licensing decision will be received this summer, allowing work on this reliability project to commence later in the year.

The Manitoba Hydro-Electric Board is comprised of 11 members whose primary responsibility is to ensure the corporation carries out its legislated mandate. In performing this oversight, the board reviews Manitoba Hydro's financial forecasts as well as quarterly and annual financial statements. Members also review and approve the corporation's strategic plan.

I would like to express my gratitude to the members of the board for their diligent work throughout the past year.

I would also like to recognize Manitoba Hydro's employees for their dedication and ongoing commitment to service.

William C. Fraser, FCA
Chair, The Manitoba Hydro-Electric Board

President's message

For most people, the act of flicking a switch or turning up a thermostat is routine. Lights are turned on and furnaces are started up without much thought to where the energy comes from.

In the past year, however, we started asking our customers to consider what is behind the switch. Our message is this: the system that served Manitoba well for many years now needs a significant investment to continue meeting the province's needs. It is an investment that will require modest, regular increases to the rates our customers pay for electricity.

Much of the infrastructure we use to deliver electricity was built several decades ago when service was first extended to urban then rural customers. It's getting old and more costly to maintain. Manitoba Hydro is still maintaining high levels of reliability – higher than most in the industry. But, the condition of our distribution assets is starting to impact reliability, outage performance and the system's ability to accommodate load growth. Like most energy utilities in Canada, we need to replace those assets that are at the end of their service life. The cost of that work is expected to be $500 to $600 million per year over the next two decades.

Manitoba also needs new sources of energy. The demand for electricity in our province is continuing to grow and, at the current rate of approximately 80 megawatts of peak demand per year, it is projected that a new source of electricity will be needed by the 2022-23 fiscal year. To meet the future needs of the province, we are planning to build the 695-megawatt Keeyask Generating Station at an estimated cost of $6.2 billion followed by the 1,485-megawatt Conawapa Generating Station at an estimated cost of $10.2 billion.

Manitoba Hydro is well positioned to make these investments while maintaining reasonable and competitive rates for our customers and ensuring the continued financial health of the corporation. This past fiscal year, the corporation continued to add to our equity base through retention of earnings. Our consolidated net income of $92 million for the fiscal year ended March 31, 2013 contributed to retained earnings which now stand at $2.54 billion, the highest level in the corporation's history. The debt to equity ratio of 75:25 is on target and both the corporation's capital coverage and interest coverage ratios improved over last year.

These measures are significant. Manitoba Hydro will need to attract and invest a large amount of capital as we face the renewal of our infrastructure and the need to develop new sources of energy. As a Crown-owned utility, we are fortunate to have the support of the provincial government to guarantee our debt. However, we must also maintain sufficient levels of net income and retained earnings to ensure the corporation remains self-sufficient. Export sales along with modest, regular domestic electricity rate increases will help us achieve this objective as we move forward.

Utilities across Canada are experiencing similar rate pressures. It's been estimated that nearly $350 billion must be spent across Canada in the next 20 years to renew and replace electricity systems. Manitoba's advantage is our electricity rates are currently among the lowest overall in North America. We are taking a prudent, proven approach to developing our system that will allow us to maintain this competitive advantage.

One way we'll do that is by leveraging the export sale opportunities associated with Manitoba's hydropower resources to create revenues that offset capital investments in new generating stations.

There continues to be a demand for clean, reliable hydroelectricity in the United States where utilities are looking to diversify their supply portfolios by replacing aging coal-fired units and limiting exposure to the price volatility in natural gas markets. Manitoba Hydro has already signed firm sale agreements with Northern States Power, Minnesota Power and Wisconsin Public Service valued at $7 billion. We are also negotiating a term sheet with Wisconsin Public Service for up to 500 megawatts of additional capacity.

We will continue to pursue demand side management where economic, providing our customers innovative solutions for conserving energy and reducing their costs while also making more electricity available for export sales. Our broad spectrum of Power Smart programs helped Manitoba Hydro's customers save a combined $102 million on their electricity and natural gas bills in 2012-13. Over the next 15 years, Manitoba Hydro will invest over $420 million to achieve reductions of approximately 1,500 gigawatt hours in electricity consumption and 60 million cubic metres of natural gas per year by 2027-28.

As a corporation, we are also carefully examining all expenditures and reducing or deferring where possible. We are gaining synergies and cost reductions through process improvements such as the implementation of our new mobile workforce management system. In the longer term, we are looking at the demographic shift that is occurring in our workforce as an opportunity. Nearly 900 employees are eligible for retirement in this calendar year. While we aren't expecting that many employees to move on, we are evaluating those positions that are vacated and determining whether they need to be filled or if we can change the way we work without sacrificing safety and reliability.

However, the potential opportunity in our workforce demographics also presents a challenge. With years of accumulated experience and knowledge, many of those at or nearing retirement age are key contributors to our success. It is important, therefore, that we do the necessary succession planning as well as recruitment and retention activities. Effectively managing this changeover in staff will be as critical to maintaining the level of service our customers expect as renewing infrastructure or building new generating stations.

It is also important that we promote and protect the health of our workforce. I am pleased to report that there were no high-risk accidents in 2012-13 and that Manitoba Hydro's overall safety performance saw another year-over-year improvement. In particular, we made good progress in reducing accident frequency and accident severity — improving both measures for the fifth year in a row.

I continue to be impressed with the quality of energy service in Manitoba and consider myself fortunate to be a part of an organization with such a long, proud tradition of customer service excellence. Over the past year, I've seen first-hand the dedication of Manitoba Hydro's employees – from the work done to restore service in difficult conditions such as the Thanksgiving Day weekend storm in southeastern Manitoba to the diligent efforts to prepare for public hearings that reviewed our rate applications and the Bipole III Transmission Project.

It reinforces my belief that Manitoba Hydro is ready to meet the challenges of providing reliable power both today and for decades to come.

I want to thank all the men and women who work for Manitoba Hydro for their contributions to the achievements of the past year. In addition, I want to acknowledge Vince Warden, who retired earlier this year from his position as Senior Vice-President of Finance and Administration and Chief Financial Officer after 45 years of service. He was a key advisor during my first year at Manitoba Hydro whose counsel was invaluable and much appreciated.

I also want to express my sincere appreciation to Bill Fraser and the other members of the Manitoba Hydro-Electric Board for their guidance and support over the past year.

Scott A. Thomson, CA
President and Chief Executive Officer
Manitoba Hydro

Established by the government of Manitoba over 60 years ago, as demand for electricity in the post-war economy flourished, the Manitoba Hydro-Electric Board was tasked with providing an adequate and economic power supply for the province. That mission hasn't changed. Whether it is natural gas or electricity, we remain focused on ensuring our customers continue to benefit from an affordable and reliable source of energy.

Vision

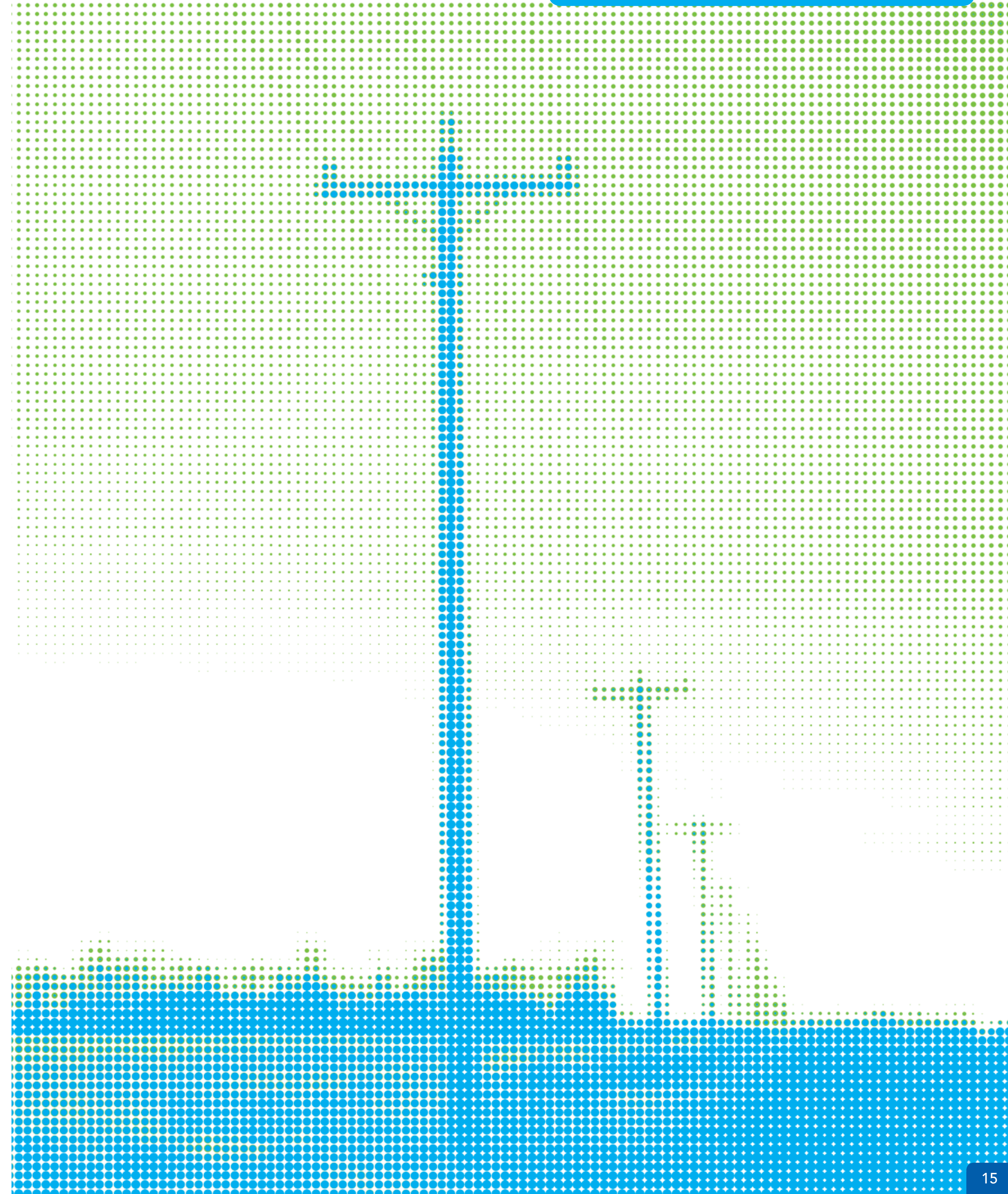
To be the best utility in North America with respect to safety, rates, reliability, customer satisfaction and environmental leadership; and to always be considerate of the needs of customers, employees and stakeholders.

Mission

To provide for the continuance of a supply of energy to meet the needs of the province and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy.

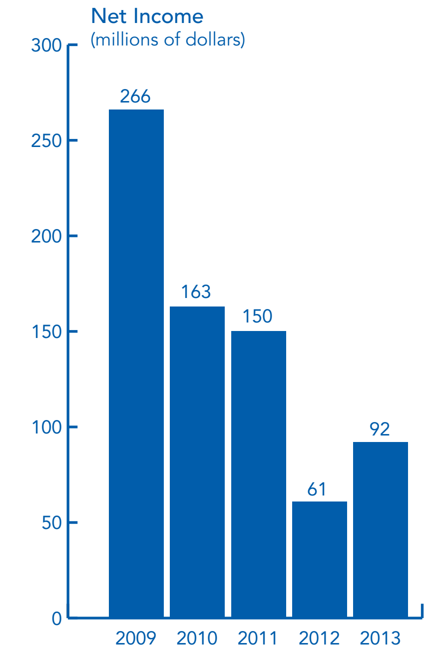
Corporate goals

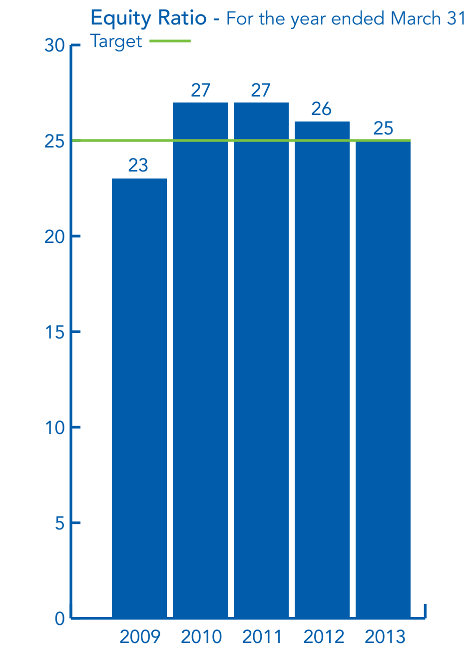
- Improve safety in the workplace.
- Provide exceptional customer value.
- Strengthen working relationships with Aboriginal communities.
- Maintain financial strength.
- Extend and protect access to North American energy markets and profitable export sales.
- Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba.
- Protect the environment in everything that we do.
- Promote cost effective energy conservation and innovation.
- Be recognized as an outstanding corporate citizen and a driver of economic development in Manitoba.

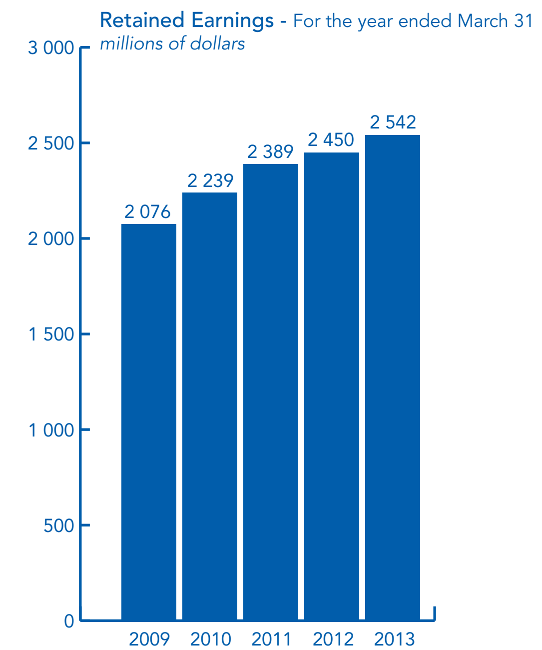


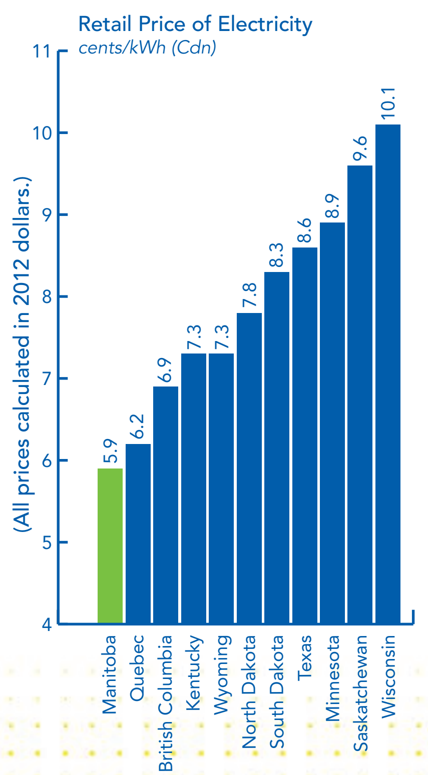
FINANCIAL RESULTS

	Electricity		Natural Gas		Consolidated		Change
Revenue	2013	2012	2013	2012	2013	2012	
			millions of dollars				
Manitoba	1 380	1 219	329	329	1 709	1 548	161
Extraprovincial	353	363	-	-	353	363	(10)
	1 733	1 582	329	329	2 062	1 911	151
Cost of gas sold	-	-	182	197	182	197	(15)
Expenses	1 662	1 515	139	138	1 801	1 653	148
Net income (loss) before non-controlling interest	71	67	8	(6)	79	61	18
Net loss attributable to non-controlling interest	13	-	-	-	13	-	13
Net income	84	67	8	(6)	92	61	31
Retained earnings	2 500	2 416	42	34	2 542	2 450	92







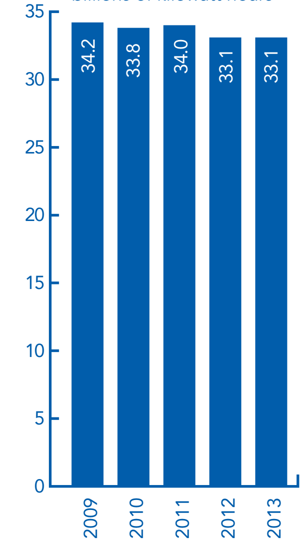


OPERATING STATISTICS

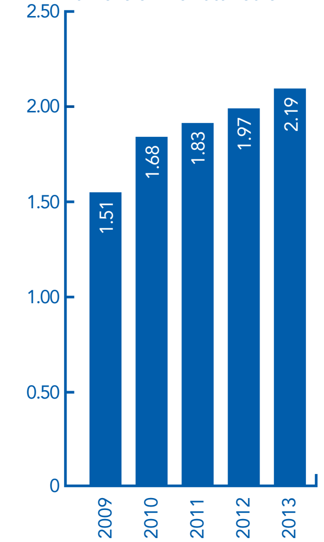
Electrical Operations	2013	2012	Increase/(Decrease)
Sales		*billions of kilowatt hours*	
Manitoba sales	21.5	20.8	0.7
Extraprovincial sales	9.1	10.2	(1.1)
System supply		*billions of kilowatt hours*	
Generation	33.2	33.2	-
Purchases	1.4	1.2	0.2
		thousands of kilowatts	
Manitoba peak load	4 535	4 343	192

Natural Gas Operations	2013	2012	Increase/(Decrease)
		millions of cubic metres	
Residential sales	602	509	93
Commercial and industrial sales	849	728	121
	1 451	1 237	214
Transportation service	598	629	(31)
	2 049	1 866	183
		billions of joules	
Manitoba peak load	504 961	500 434	4 527

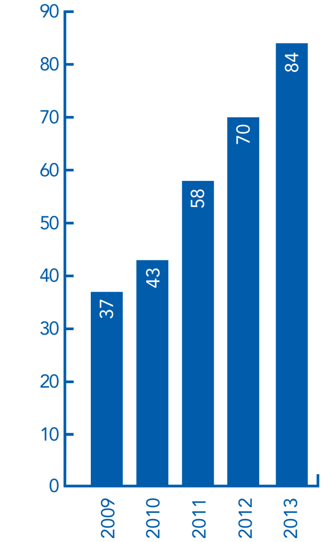
Total Hydraulic Generation
For the year ended March 31
billions of kilowatt hours



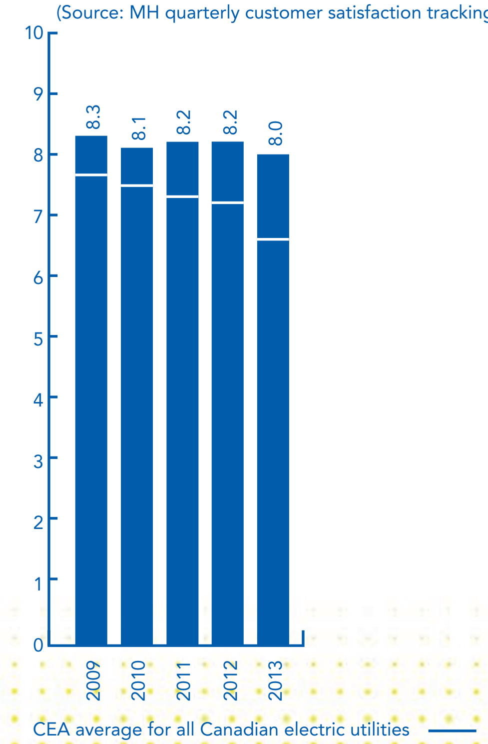
Power Smart Savings - Electricity
For the year ended March 31
billions of kilowatt hours



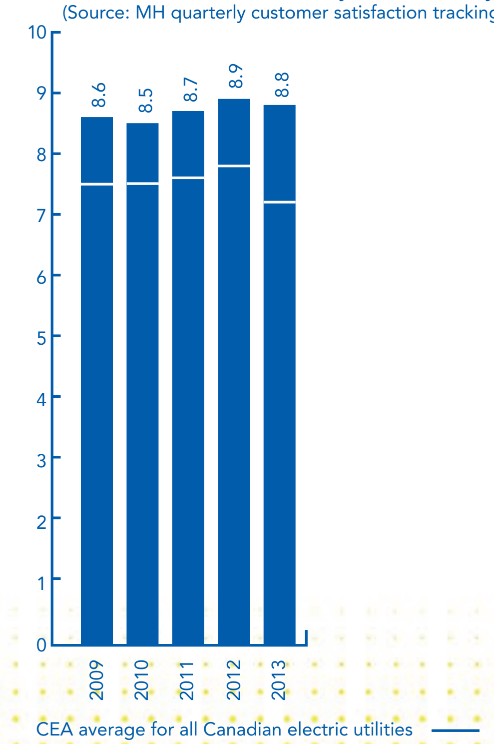
Power Smart Savings - Natural Gas
For the year ended March 31
millions of cubic metres



Customer Satisfaction with Overall Service
(Source: MH quarterly customer satisfaction tracking study)



Customer Satisfaction with System Reliability (electricity)
(Source: MH quarterly customer satisfaction tracking study)



On Resources

Situated where some of the largest drainage basins in North America converge, Manitoba is home to an impressive source of clean, renewable water power. Our customers tap into this power at 15 generating stations which produce nearly all of Manitoba Hydro's electricity. We also export about a third of this electricity in an average water year, creating additional revenues that reduce rates in Manitoba. The hydro system is supported by two small thermal generating stations, power purchased from two independent wind farms and a dozen transmission interconnections with neighbouring utilities. In 2012-13, Manitoba Hydro invested $472 million to ensure we continue to meet our customers' energy needs, reliably and affordably.

Installed generating capability: **5 685** megawatts.

Average annual energy produced: **32 billion** kilowatt hours.

Energy exported in 2012-13: **9.1 billion** kilowatt hours.

First power at the Wuskwatim Generating Station

A major milestone was achieved in June, when the first of three units at the 200-megawatt Wuskwatim Generating Station entered commercial service. The second unit was released for service two months later in August and the final unit followed in October. In total, the $1.8 billion Wuskwatim Project will deliver an average of 1 550 gigawatt hours of renewable energy annually.

Developed by the Wuskwatim Power Limited Partnership — a unique partnership involving Manitoba Hydro and the Nisichawayasihk Cree Nation (NCN) — the Wuskwatim Generating Station is on the Burntwood River approximately 45 kilometres southwest of Thompson within NCN's traditional territory. The Wuskwatim Project Development Agreement signed in 2006 provides NCN the option to own up to one-third of the Wuskwatim Generating Station through its wholly-owned Taskinigahp Power Corporation. NCN confirmed its intention to maintain a significant ownership position during the fiscal year.

From the beginning of construction in August 2006 to completion in December 2012, just over 6 000 workers were hired to work on the project for various periods of time. Approximately 37 percent of these hires were Aboriginal and 65 percent were from Manitoba.

Environmental review set for Keeyask Generating Station

The environmental impact statement for the proposed 695-megawatt Keeyask Generating Station was submitted to Manitoba Conservation and Water Stewardship and the Canadian Environmental Assessment Agency in July. Public hearings on the project by the Clean Environment Commission are scheduled for the fall of 2013.

The Keeyask Generating Station will be part of a Needs For and Alternatives To review that will examine Manitoba Hydro's proposed development plan, including the Conawapa Generating Station, a new Manitoba to U.S. transmission interconnection and new long-term export sales. This review will be conducted by the Manitoba Public Utilities Board. Manitoba Order in Council 128/2013 sets out the terms of reference. The review commences August 2013.

The $6.2 billion Keeyask Project is being developed by Manitoba Hydro in partnership with the four Keeyask Cree Nations — Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. The site for the station is on the Nelson River, approximately 30 kilometres west of Gillam, within the Split Lake Resource Management Area. Once completed, the Keeyask Generating Station will provide an average of 4 400 gigawatt hours of renewable energy each year.

At the end of the fiscal year, the process was underway to select a general civil contractor for the project. Pending regulatory approvals, construction of the generating station is scheduled to start in June 2014 with an expected in-service date of 2019.

To minimize risk of delays and optimize employment, training and business opportunities for the Keeyask Cree Nations, a separate infrastructure agreement was negotiated to enable an early start to construction of an access road and the first phase of the main construction camp. Work on the Keeyask Infrastructure Project began in early 2012 after a Manitoba Environment Act licence was received.

The majority of service contracts for the infrastructure project were awarded to joint venture partnerships involving the Keeyask Cree Nations.

Planning continues for Conawapa Generating Station

Preparatory work on the proposed 1 485-megawatt Conawapa Generating Station continued throughout the fiscal year. Environmental and Aboriginal traditional knowledge studies are underway with expectations that the project's environmental impact statement will be completed and ready to file with regulators by the end of 2014. Engineering and construction planning activities also continued with a potential construction start date of 2016 and an in-service date of 2025.

The $10.2 billion Conawapa project would be built on the Nelson River, about 90 kilometres downstream of Gillam, in the Fox Lake Resource Management Area. When complete, the station will produce an average of 7 000 gigawatt hours of electricity annually.

A formal planning process is ongoing with communities in the vicinity of the proposed generating station, including Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, War Lake First Nation and Shamattawa First Nation. A memorandum of understanding between Fox Lake Cree Nation, the Province of Manitoba and Manitoba Hydro recognizes that Fox Lake will have a leading and significant role in the planning process of the Conawapa Project because of its proximity to the community.

New spillway for Pointe du Bois

Significant progress was achieved at the Pointe du Bois Generating Station where century-old spillway structures will be replaced with a seven-bay spillway and an earth-fill dam. Excavation of the new spillway channel finished in March and the new spillway structure is expected to be operational by spring 2014. Construction of the earth-fill dam and removal of the existing spillway structures is scheduled for completion in 2015.

The $560 million Spillway Replacement Project is required to maintain public and dam safety as well as provide a safer work environment for Manitoba Hydro employees. All but six of Pointe du Bois' 97 spillway bays or sluiceways have to be manually operated — a difficult and sometimes dangerous task in cold winter conditions when icing can occur. Further, the current spillways no longer meet the Canadian Dam Association's dam safety guidelines.

The new spillway structure will increase the station's flood capacity from approximately 2 850 cubic metres per second — the equivalent of a one-in-90-year flood event — to approximately 5 000 cubic metres per second.

Seasonal diversity agreement extended

In December, Manitoba Hydro and Great River Energy of Minnesota signed a term sheet for the seasonal exchange of 200 megawatts of capacity and associated energy from 2014 to 2025. The arrangement would provide Manitoba Hydro with 200 megawatts of firm capacity and energy during Manitoba's peak winter demand period. During the summer, when demand in Manitoba is lowest, the corporation would sell its surplus capacity and energy to Great River Energy.

The proposed arrangement would begin on November 1, 2014 and replace an existing 150-megawatt diversity exchange agreement that is currently set to expire on April 30, 2015.

Kelsey re-runnering nears completion

The last generating unit to be overhauled as part of a re-runnering project at the 52-year-old Kelsey Generating Station was taken out of service in September. The second-to-last unit was returned to service in May 2012 after rewinding, modifications to the draft tube and installation of a new turbine runner. The work increased the capacity of the unit by approximately 11 megawatts to 45 megawatts.

Rehabilitation of Kelsey's seven units began in 2006. The final unit is scheduled for return to service in late May 2013. When complete, the project is expected to increase the total output of the Kelsey Generating Station by about 77 megawatts at a cost of approximately $300 million.

More wind energy added

Ten additional wind turbines were built at Algonquin Power's St. Leon Wind Farm in the past fiscal year as the result of a 25-year power purchase agreement signed with Manitoba Hydro. The new turbines entered commercial service in December, increasing the installed capacity at St. Leon to 120.5 megawatts.

Manitoba Hydro also purchases energy from the 138-megawatt St. Joseph Wind Farm developed by Pattern Energy.

Left: The Wuskwatim Generating Station. Right: Senior staff, including Ken Adams, Senior Vice-President of Power Supply, pictured second from left, accompany Scott Thomson, President and Chief Executive Officer, second from right, on a visit to the site of the proposed Conawapa Generating Station.

On Reliability

Any time our customers turn on a light, plug-in a computer or ignite a gas stove, they are connecting to a vast network of wires and pipes that deliver energy where and when it's needed. Our network has grown, and must continue to grow, in step with the province we serve. In the past fiscal year, Manitoba Hydro invested $509 million to build and maintain a secure, dependable delivery system.

Transmission lines: **12 800** kilometres.

Distribution lines: **78 000** kilometres.

Natural gas pipelines: **9 000** kilometres.

Bipole III environmental review hearing concludes

In March, the Clean Environment Commission concluded 35 days of hearings over five months to review the environmental impact statement for the Bipole III Transmission Project as well as a supplementary filing on four proposed route adjustments. An environmental licensing decision is pending.

Bipole III is required to strengthen Manitoba Hydro's overall system reliability. The $3.3 billion project includes: a 1 384-kilometre, 500-kilovolt direct current transmission line; the Keewatinoow Converter Station near the site of the proposed Conawapa Generating Station about 90 kilometres downstream of Gillam; and the Riel Converter Station on the east side of Winnipeg. These facilities will provide backup to the Bipole I and II high voltage direct current system which shares a common right-of-way corridor and common southern terminus at the Dorsey Converter Station. This critical system delivers over 70 percent of the hydroelectricity Manitoba Hydro generates in northern Manitoba to customers in the south and markets outside of the province.

Work to identify a route and assess the environmental effects of the Bipole III Transmission Project began in 2008 and included multiple rounds of public and stakeholder consultations. Aboriginal communities were engaged as part of this process and their perspectives, including

Aboriginal traditional knowledge, were incorporated into the planning, site selection and environmental assessment process. The corporation continued to work with Aboriginal communities over the past fiscal year to discuss potential employment and business opportunities related to the project as well as review the project's proposed environmental protection program.

The target in-service date for the Bipole III Transmission Project is late 2017.

New Riel high voltage terminal will improve reliability

Contractors were erecting structural steel and other equipment at the new Riel Terminal Station at the end of the fiscal year. Under construction just east of Winnipeg, at the future site of the Riel Bipole III Converter Station, this new alternating current (AC) terminal will create another point where electricity imported from the United States on an existing 500-kilovolt transmission interconnection can be injected into Manitoba Hydro's transmission network. This will improve the reliability of the province's energy supply during prolonged outages to existing termination facilities or during droughts.

The Riel AC Reliability Improvement Project was undertaken after studies concluded it was necessary to reduce dependence on the existing termination at the Dorsey 500-kilovolt AC station. Those studies were conducted after a major wind downburst in September 1996 severely damaged 19 towers on both high voltage direct current lines immediately north of the Dorsey Converter Station and the adjacent Dorsey to Minnesota 500-kilovolt transmission line. This outage to the high voltage direct current system curtailed Manitoba Hydro's ability to transmit power from northern generating stations. The planned in-service for this project is 2014.

The proposed Bipole III Transmission Project will also terminate at Riel and include the addition of converters and ancillary equipment.

Replacing aging distribution stations

Like many utilities across Canada, significant portions of Manitoba Hydro's transmission and distribution systems that were installed decades ago are aging and are increasingly costly to maintain and renew. In addition, population growth and increased customer use of electricity requires a significant investment in new facilities to ensure a reliable electricity supply.

One example of this investment is the work at the new Burrows Distribution Station in Winnipeg's north end where final commissioning was underway at the end of the fiscal year. The 66- to 12-kilovolt station replaces two distribution stations which were over 75 years old and had reached the limits of their capacity. Designed with specific attention to safety and aesthetics because of the proximity to residential homes, the station offers a low profile presence in the community.

In February, work began on the new Martin Distribution Station in the Elmwood neighbourhood of Winnipeg. Similar in design to the Burrows station, the 66- to 12-, four-kilovolt Martin station is sited next to a station built in the 1950s that is no longer adequate for serving the needs of the area. The new station is scheduled to be in-service by the end of 2014.

Left: The new Riel Terminal Station under construction east of Winnipeg. **Right:** Three transformers were moved to the Riel site in November using a 320-tire self-propelled trailer.

Tenders for the engineering, materials procurement and construction of the Madison Distribution Station were issued in March. The Madison station will replace the St. James Distribution Station in Winnipeg, addressing concerns with aging infrastructure at the existing facility and providing capacity for the growing number of commercial and industrial customers in the area. Construction is expected to begin in the fall of 2013 pending the receipt of necessary environmental approvals.

New transmission stations add capacity

Progress was also made on a number of projects to add needed capacity to Manitoba Hydro's transmission system. The new 230- to 66-kilovolt Transcona East Transmission Station was completed in March in northeast Winnipeg and will resolve line-loading issues and accommodate the retirement of aging equipment at the existing Transcona Station. A new 230- to 66-kilovolt transmission station is under construction near Neepawa to meet forecast load growth in the area and scheduled to be in-service in 2015. And, the 230- to 115-kilovolt Rockwood East Transmission Station just north of Winnipeg is also scheduled to enter service in 2015, addressing load requirements north of Winnipeg. Rockwood East will eventually replace the older Parkdale Station near St. Andrews which was built in the 1940s.

Verifying ratings to maximize capacity

When transmission line wires carry more current, they run hotter, expand and sag closer to the ground. By ensuring compliance with applicable transmission line clearance requirements, Manitoba Hydro's Transmission Line Rating Verification and Mitigation Program helps maintain the reliability of the system while allowing the corporation to safely maximize capacity. Using aerial surveys that employ laser technology and transmission modeling applications, the program assesses about 500 kilometres of transmission line each year. As of March, approximately 33 000 line spans had been assessed representing about 80 percent of the corporation's transmission lines.

Maintaining natural gas reliability

Manitoba Hydro undertook a number of projects in the past fiscal year to maintain the integrity of the corporation's natural gas infrastructure, including pressure regulator upgrades, replacement of gas mains and corrosion control through the ongoing replacement of anodes. The completion of the Ile des Chenes Transmission Network Upgrade Project improved the reliability of the gas supply to Winnipeg and surrounding areas through the installation of 30-centimetre steel pipe and two above grade isolation valve assemblies.

Manitoba Hydro also initiated a review of its natural gas assets. Similar to condition assessments undertaken with the corporation's electric infrastructure, the review will provide a better understanding of the natural gas systems condition and produce recommendations for addressing any areas of concern that are identified.

Left: The King Street Distribution Station in downtown Winnipeg is nearly 100 years old. **Centre:** A 45 000-kilogram transformer is slid into place at the new Burrows Distribution Station. **Right:** Staff remove a 230-kilovolt bushing at the Radisson Converter Station.

On Service

Striving to be the best energy utility in North America requires more than developing sustainable energy sources or building reliable infrastructure to deliver that energy. It necessitates maintaining rates that are reasonable while ensuring future price stability. It requires working in challenging conditions, when called for, to restore interrupted service. And, it means finding innovative ways to help customers get the most out of their energy. An investment of $36 million in Power Smart energy conservation programs helped our customers reduce their energy costs by a combined $102 million in 2012-13.

Number of electricity customers: **548 774**

Number of natural gas customers: **269 786**

Increasing accessibility of energy efficiency

Manitoba Hydro introduced two initiatives in the past fiscal year to make energy efficiency accessible to more Manitoba homeowners or tenants who rent a home.

The Power Smart Pay As You Save (PAYS) Financing Program provides residential customers a convenient option for completing energy efficiency upgrades while keeping upfront costs and future monthly finance payments as small as possible. To do this, PAYS Financing allows a customer to use estimated annual utility savings gained from installing energy efficient measures to pay for those measures. Also, the financing is tied to the property, allowing a customer to transfer their financing to the next homeowner or tenant renting the property.

Through the Power Smart Neighbourhood Project, Manitoba Hydro is working with community organizations and groups to bring the benefits of energy efficiency and sustainability to residents of lower income neighbourhoods. Available measures include free in-home energy reviews, improvements to sealing, caulking and weather-stripping, adding pipe wrapping and water efficiency devices, installing new high-efficiency furnaces and boilers, and insulation upgrades. Community groups will manage each project and Manitoba Hydro will provide funding to cover coordination and promotion expenses. As of March, projects were underway in Winnipeg with the North End Community Renewal Corporation and in Brandon with the Brandon Neighbourhood Renewal Corporation.

Helping customers save

Manitoba Hydro offered both technical and financial support to customers looking to improve the efficiency of their operations and reduce energy costs through a suite of 20 Power Smart programs, including 10 for those in the commercial sector and three aimed at industrial customers.

Kitchen Craft of Canada, for example, was able to realize significant energy savings by revamping the compressed air system at their manufacturing plant in Winnipeg. Acting on recommendations by Manitoba Hydro, Kitchen Craft reduced system waste by redesigning their air compressor control system, resizing their air distribution system and adding more efficient compressors. As a result, Kitchen Craft reduced their electricity consumption by 1.6 million kilowatt hours per year. With the help of financial incentives provided under Manitoba Hydro's Power Smart Program, these improvements will pay for themselves in four years.

The corporation's Natural Gas Optimization Program and the Performance Optimization Program provided financial incentives to Malteurop Canada helping to improve the performance of their malt barley processing plant in Winnipeg. Exhaust air heat recovery and high efficiency process air heaters were installed, along with variable speed drives on the kiln fans and upgrades to process controls. As a result, Malteurop is expected to reduce their natural gas consumption by 640 000 cubic metres and their electricity consumption by 2.3 million kilowatt hours per year.

The Hanover School Division worked with Manitoba Hydro to build a new school in Steinbach to Power Smart Design Standards. Clear Spring Middle School is nearly 70 percent more energy efficient than a conventional school thanks to features such as a geothermal ground source heat pump for heating and cooling, energy efficient lighting plus a combination of occupancy sensors and daylight controls to minimize the use of artificial light, high levels of insulation in the walls and roof along with energy efficient windows and doors. The corporation provided technical advice throughout the design process as well as financial incentives through the Power Smart Commercial Lighting and Building Envelope programs.

Demonstrating benefits of bio-energy

A demonstration project that converts waste wood chips into a synthetic gas similar to natural gas then burns that gas to run two 50-kilowatt electrical generators went online last fall at the Pineland Forest Nursery near Hadashville. In Swan River, Spruce Products Ltd. also began using heat produced from combusted waste wood to operate a 100-kilowatt electric generator.

Both projects are part of Manitoba Hydro's Power Smart Bio-energy Optimization Program which shows businesses how to use new technologies to take advantage of renewable biomass fuels and lower operating costs. A third project was completed at Tolko Industries' kraft paper mill in The Pas in 2010 to demonstrate pyrolysis oil, a renewable energy source

Left: Scott Thomson, President and Chief Executive Officer, speaks to media after introducing the new Power Smart Pay As You Save Financing Program. **Centre:** Manitoba Hydro offers 13 Power Smart Programs to help business customers lower energy costs. **Right:** The Power Smart Bio-energy Optimization Program showcases technologies that can convert waste products into electricity or heat.

derived from waste wood that can be used to replace fossil fuels burned to produce steam or power. Two additional demonstration projects will be implemented at other customer sites in the coming fiscal year. All five projects received financial support from the Government of Canada's Clean Energy Fund matched by Manitoba Hydro and participating customers through work-in-kind contributions and capital investments.

Centralized dispatch serving province

Manitoba Hydro completed implementation of a new province-wide workforce management system in March that is improving productivity. The system standardizes work planning, scheduling and assignment for all electric and natural gas service staff. Over 600 laptops are deployed in vehicles allowing field staff to wirelessly receive work orders which are assigned based on location, driving time, work priority and skills required. It is expected that customers will see improved response times as a result of the system's ability to more effectively schedule work and allocate resources.

Severe snow and ice storms challenge crews

Ice and snow storms are not uncommon in Manitoba. In fact, Manitoba Hydro is a recognized leader in techniques to protect infrastructure in such conditions, including ice-melting on distribution and some transmission lines. This year, however, two severe storms — including the most powerful and widespread snow storm in nearly three decades — caused extensive damage and service interruptions.

Up to 45 centimetres of heavy, wet snow fell in the southeast corner of Manitoba between October 4 and 5, causing record ice accumulations of up to eight centimetres on conductors. These conditions combined with high winds caused outages on numerous transmission and distribution lines affecting approximately 29 000 customers. Over 250 staff from across the province responded to the storm, rolling ice off conductors, making conductor repairs and removing trees from lines. In total, 250 wood poles, 50 cross-arms, five distribution transformers and 700 insulators were replaced over five days.

Crews were also busy in the western part of the province during the month of December. For three weeks, unseasonably warm temperatures accompanied by freezing rain and hoar frost caused excessive ice accumulations on distribution lines. Over 300 staff rolled ice from nearly 4 500 kilometres of line and used ice-melting to clear an additional 2 300 kilometres of line. About 800 customers experienced outages ranging from one hour to 14 hours in duration. The ice removal work was successful in limiting damage to 12 wood poles, 613 conductor repairs and 58 insulator replacements.

Left: Crews work to remove ice from lines near Goodlands in southern Manitoba. **Centre:** A new centralized dispatch system is expected to improve response times. **Right:** Staff work to complete repairs after a severe storm in the Dauphin and Swan River area last June.

Electricity rate changes

On September 1, 2012, Manitoba Hydro implemented an interim 2.4 percent overall electricity rate increase. This followed an interim two percent increase implemented on April 1, 2012. Both increases were granted by the Manitoba Public Utilities Board pending conclusion of its review of the corporation's 2012-13 and 2013-14 general rate application.

In its final order, the Public Utilities Board finalized the interim rate increases and approved a further 3.5 percent rate increase across all customer classes effective May 1, 2013. The order also reversed a one percent rate rollback effective April 1, 2010 and returned associated revenues which had been held in a deferral account.

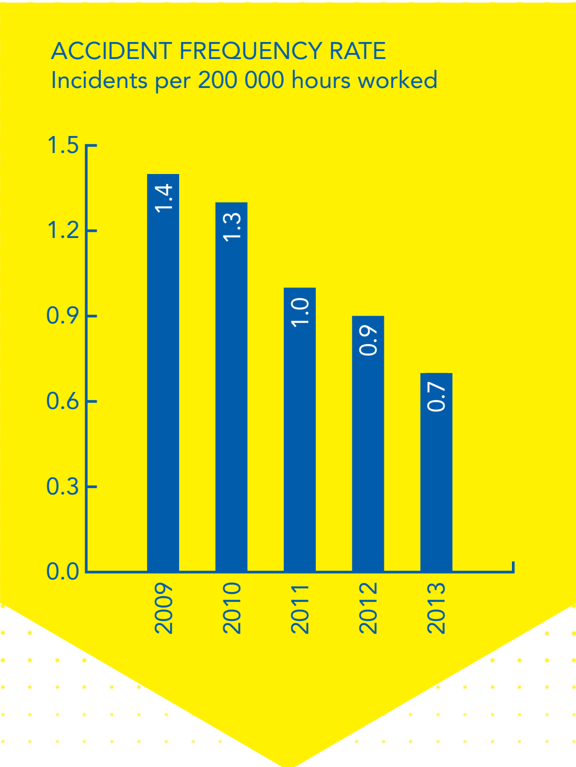
Manitoba Hydro's electricity customers continue to enjoy the lowest rate structure in North America.

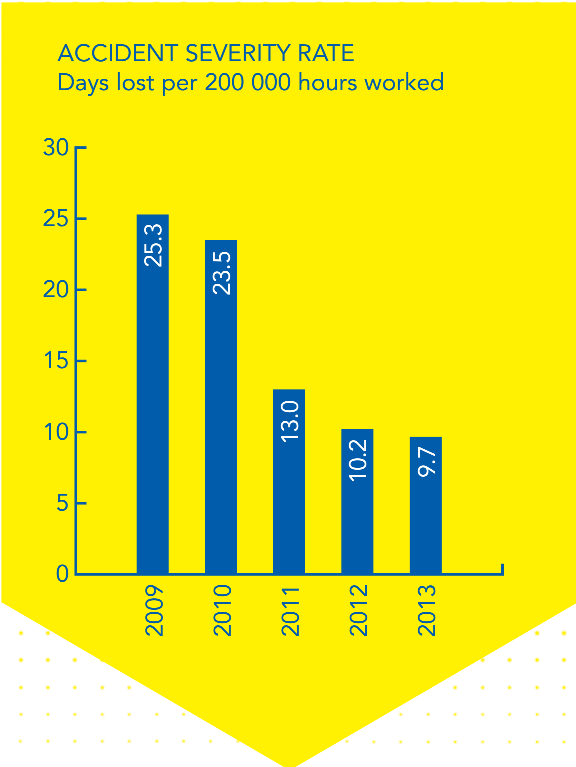
Natural gas rates decline

Natural gas prices across North America remained low throughout the 2012-13 fiscal year and Manitoba Hydro's natural gas customers benefitted as a result. The total annual natural gas bill for a typical residential customer in Manitoba was 44 percent lower than in 2003. From April 1, 2012 to March 31, 2013, natural gas rates declined by six percent or the equivalent of $46 annually for a typical residential customer.

On Safety

Promoting safety in the work of our employees and in the actions of the public around our facilities is Manitoba Hydro's foremost goal. We are continually seeking to improve our safety performance and, in doing so, have achieved a steady decline in both workplace accident severity and frequency rates.





Improving workplace safety

Manitoba Hydro's safety performance markedly improved for the fifth consecutive year. In 2012-13, the corporation achieved an accident frequency rate of 0.72 incidents per 200 000 hours worked and an accident severity rate of 9.68 calendar days lost due to workplace injury or illness per 200 000 hours worked.

Manitoba Hydro's safety culture is shaped by a safety management system, over 750 safe work procedures, job planning, work site visits, employee orientations, safety training and incident investigations. Additionally, Manitoba Hydro assists its employees to return to work as soon as medically possible through attendance management and reasonable accommodations. Timely return to the workplace decreases recovery time and reduces the financial impact for the employee, their families and the corporation.

Profiling employees committed to safety

Twelve employees who demonstrate safe work habits and a commitment to motivating others to practise safety at work and at home are the subject of a year-long internal safety campaign that kicked off in January. Each month the corporation's internal newsletter as well as calendars and banners posted in work locations across the province feature a different safety ambassador's photo and story describing why he or she chooses to work safe. Primarily directed at customer service field staff, this is the second year for the safety campaign.

Farm safety a priority

Farm safety continues to be a priority for Manitoba Hydro. The corporation's agricultural equipment move permit program encourages farm customers to provide a designated route map to ensure there are adequate clearances to move oversized equipment. The Go Underground Program encourages customers to bury overhead power lines in their farm yards. Manitoba Hydro will share 50 percent of the cost of burying the primary service line up to $10 000. In the last fiscal year, 18 customers took advantage of the program.

These farm safety programs were promoted through billboards, posters and public service announcements on radio and television. Agricultural safety messages were also delivered to over 2 000 youth in 16 communities at Progressive Agriculture Safety Days.

Play It Safe Club celebrates

2013 marks the twentieth anniversary of Louie the Lightning Bug's Play It Safe Club which continues to be a popular, fun and educational way for children to learn about electrical and natural gas safety. The nearly 7 000 members of the club receive a personally addressed membership kit, collectible trading cards, newsletters full of activities and birthday wishes from Louie himself. In addition to the club, Louie also keeps busy spreading safety messages through videos, posters, television commercials and personal appearances across the province.

Promoting snowmobile safety

The corporation continued to work closely with Snoman Inc., a non-profit organization providing safety resources to 51 member snowmobile clubs. The past year's safety campaign included trail map advertising, billboard messages throughout the province, school posters, television advertising and public service announcements for radio and newspaper. Support was also provided to community snowmobile safety clinics in Victoria Beach and Thompson.

Throughout 2013, these twelve safety ambassadors will share their personal reasons for choosing to work safe as part of an internal safety campaign.

On Environment

Manitoba Hydro endeavours to incorporate environmental awareness and protection into all our activities. We proactively plan to prevent or mitigate adverse impacts from our projects. We maintain a corporate-wide environmental management system registered to ISO 14 001 standards. We also support environmental research and education initiatives relevant to our operations.

Amount of generation from renewable sources:
99 percent

Manitoba Hydro Place certified platinum

In May, Manitoba Hydro's head office building became the first office tower in Canada to achieve a platinum certification from the Green Building Council of Canada for adherence to Leadership in Energy and Environmental Design (LEED) standards. Completed in 2009, Manitoba Hydro Place is already recognized as the most energy efficient office tower in North America. Compared to conventional office towers, Manitoba Hydro Place achieves reductions in energy use of over 70 percent — from over 300 kilowatt hours per square metre to under 85 kilowatt hours — resulting in estimated energy savings of over $500 000 annually.

These savings were achieved thanks to a unique building design that utilized leading-edge Power Smart technologies as well as passive and active energy efficient systems. These include south-facing winter gardens to capture the maximum amount of solar energy during winter months, a solar chimney to provide ventilation with minimum energy usage and the extensive use of glass to allow for natural lighting.

Manitoba Hydro Place also received the 2012 International Green Good Design Award and was one of 14 developments from around the world to receive a 2012 Urban Land Institute Global Awards for Excellence.

Wuskwatim fish habitat enhancement

While construction of the Wuskwatim Generating Station was completed in the fiscal year, fish habitat enhancement work related to the project is continuing. To obtain a Fisheries Act Authorization to construct and operate the station, the Wuskwatim Power Limited Partnership submitted a No Net Loss Plan to Fisheries and Oceans Canada describing how fish habitat lost during construction would be offset.

Those offsets include building an isthmus to protect areas of Wuskwatim Lake from wave action, using rock to construct whitefish spawning reefs and creating more than 300 boulder clusters on the lake bottom to create variability in an effort to promote use by fish. Debris was also removed from an embayment at the base of what was Taskinigup Falls and aquatic vegetation planted to create habitat. An access road used during construction will be converted into a notched weir in 2013-14 to control water levels in the embayment while allowing access for fish.

The effectiveness of the habitat enhancement works will be monitored in the years following completion and results will be reported annually to Fisheries and Oceans Canada.

Enhancing sturgeon stewardship

Manitoba Hydro concluded negotiation of a lake sturgeon stewardship agreement for the lower Nelson River with area First Nations and the fisheries branch of Manitoba Conservation and Water Stewardship. Signed by Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation, Fox Lake Cree Nation and Shamattawa First Nation, the agreement establishes the Lower Nelson River Sturgeon Stewardship Committee – a forum where all parties will work collaboratively to develop a regional stewardship plan. Such a plan will set out comprehensive research and monitoring measures as well as objectives and strategies for the protection and enhancement of lake sturgeon populations.

The stewardship committee will also support Manitoba Hydro's Lake Sturgeon Stewardship and Enhancement Program and work in partnership with Keeyask Cree Nations to protect and enhance lake sturgeon populations by incorporating extensive design features and mitigation measures into the Keeyask Generating Station Project.

Lower Churchill River confluence study

An assessment of flow conditions in a known sturgeon spawning area located at the confluence of the Little Churchill and Churchill rivers was completed in the past fiscal year. Initiated by Manitoba Hydro and the Tataskweyak Cree Nation in 2010, the Lower Churchill River Confluence Study examined the role flows in each river play in sturgeon access to the Little Churchill and described habitat characteristics important to sturgeon in the area.

Since 1976, Manitoba Hydro has diverted a portion of Churchill River flows into the Nelson River for hydroelectric production purposes. The study concluded that flows on the Churchill River in drought conditions do not impact the Little Churchill and thus do not diminish sturgeon spawning potential on that river.

Supporting environmental awareness initiatives

Manitoba Hydro's Environmental Partnership Fund supported over 20 community-based projects in 2012, including the Provincial Rod and Reel Program run by Fish Futures. The program delivered a stewardship message as well as rods, reels and tackle to over 600 students located in northern

Left: Students at Little Black River School learn forest research skills thanks to funding from Manitoba Hydro's Forest Enhancement Program. **Centre:** Manitoba Hydro is working to increase the province's sturgeon population. **Right:** Manitoba Hydro's head office building in downtown Winnipeg is the most energy efficient office tower in North America.

Manitoba. The students were given the opportunity to participate in a hands-on activity and learn about fish habitat and biology.

Established in 1993, the Environmental Partnership Fund provides one-time or multi-year contributions to support the development and implementation of environmental education projects with a sustainable development focus.

With funding from Manitoba Hydro's Forest Enhancement Program, youth at Little Black River School developed forest research skills and reconnected to the surrounding forest in their community. The students also planted 500 trees on their school property while learning about many benefits of planting trees; absorbing greenhouse gases, producing oxygen, stabilizing the soil and providing habitat for birds and small mammals.

In 2012, 42 projects from around Manitoba received funding through the program which will enhance community forests and support forest education. Over 113 000 trees have been planted as a result of the program since 1995.

One of Canada's greenest

In March, the editors of Canada's Top 100 Employers project named Manitoba Hydro one of Canada's greenest employers. Competing employers were evaluated on four main criteria: unique environmental initiatives and programs; success at reducing their environmental footprint; the degree to which employees are involved in these programs; and the extent to which these initiatives are linked to the organization's public identity.

Manitoba Hydro's selection recognized a number of initiatives, including the corporation's environmental management system designed to ensure impacts from ongoing and future operations are addressed, work to preserve lake sturgeon, a centralized facility to ensure proper disposal of both hazardous and non-hazardous waste, and the Education for Sustainable Development Grants Program.

On Relationships

Manitoba Hydro's commitment to being an outstanding corporate citizen is manifest in our work to create positive relationships with our customers, our employees and their representatives, Aboriginal communities and other stakeholders. It is also evident in our efforts to recruit a workforce that reflects the diversity of our province and in the support we provide to community activities.

Number of employees:
6 463

Women:
25 percent

Aboriginal:
17 percent

Persons with disabilities:
10 percent

Visible minorities:
7 percent

Building a skilled and diverse workforce

Manitoba Hydro was selected as one of the nation's leading employers and one of the best diversity employers for 2013 by the editors of Canada's Top 100 Employers who recognized the corporation's many workplace diversity and inclusiveness programs.

Examples include the corporation's Northern and Southern Aboriginal Pre-placement Training programs, and the Aboriginal Line Trades Training Program. These programs provide on-the-job training, academic upgrading, mentorship and guidance to help Aboriginal candidates acquire the skills and competencies to successfully move into Manitoba Hydro's technical trades training programs. In the past fiscal year, 26 candidates successfully completed the pre-placement training and were selected for the power electrician, operating technician or line trades training programs. A combined 29 new trainees were hired into the pre-placement training programs.

Another example is the corporation's Acquired Brain Injury Program. Designed to reintegrate people who have sustained a severe brain injury into the workforce, 10 participants have become permanent employees since the program was first implemented in 2002. Two individuals began work placements with Manitoba Hydro as part of the program in the fiscal year.

Two graduates of the University of Manitoba's Internationally-Educated Engineers Qualification (IEEQ) Program were hired into Manitoba Hydro's Internationally Educated Engineer – Career Development Program and the Engineer-in-Training Program during the past fiscal year. Another graduate of the program was also hired direct to a permanent professional engineering position. The IEEQ Program supports engineers who trained abroad in fulfilling the academic requirements of the Association of Professional Engineers and Geoscientists of Manitoba. Manitoba Hydro provides cooperative work terms and, since 2004, has awarded annual bursaries worth $1 500 to two students enrolled in the program.

Manitoba Hydro supported continued education in programs that connect to high demand occupations in 2012. Fifty-nine individual awards, bursaries and scholarships valued at over $180 000 were awarded to students at the high school, college and university levels.

The corporation has established positive and mutually beneficial working relationships with four certified bargaining units – the International Brotherhood of Electrical Workers Local 2034, the Canadian Union of Public Employees Local 998, the Association of Manitoba Hydro Staff and Supervisory Employees, and the Communications, Energy and Paperworkers Union Local 681 – as well as the Manitoba Hydro Professional Engineers Association. The corporation also liaises regularly with the Allied Hydro Council, the official bargaining agent for the 17 international and 19 local unions whose members are involved in the construction of northern generation facilities.

Strengthening relationships with Aboriginal peoples

Manitoba Hydro continued to build relationships with Aboriginal peoples by addressing the effects of its operations on their communities, by promoting and pursuing business relationships with Aboriginal companies and by fostering an appreciation of Aboriginal culture in the workplace.

Out of $470 million in contracts awarded to Manitoba companies in the past fiscal year, $49 million went to Manitoba Aboriginal companies. Manitoba Hydro uses procurement strategies and policy to create business opportunities for Aboriginal enterprises. These strategies include restricted tendering or creation of smaller custom work packages to suit the business capacities of a community in proximity of the work.

Left: Some of Manitoba Hydro's Corporate Facilities staff with a Project Search student pictured at centre. **Centre:** Elder Bill Compton shared teepee teachings with Manitoba Hydro employees as part of Aboriginal Awareness Week in May. **Right:** Manitoba Hydro continued as title sponsor of the Power Smart Winnipeg Santa Parade in November.

In November, the Manitoba Métis Federation signed an agreement with Manitoba Hydro on behalf of the primarily Métis trappers from Duck Bay and Camperville to address all impacts of the Grand Rapids Project on commercial trapping, past, present and future. The corporation provided funds to the Manitoba Métis Federation for distribution as compensation to individual trappers or eligible survivors according to the principles in the agreement.

Over 135 000 kilometres of waterways in the Saskatchewan, Burntwood, Churchill and Nelson River systems were patrolled between June and October 2012, as part of Manitoba Hydro's Waterways Management Program. The program enhances the safety of northern waterways with its Safe Travel Routes, Debris Management and Boat Patrol Initiatives. A total of 18 boat crews employing Aboriginal people from communities in northern Manitoba complete a wide range of tasks including placing navigational markers, collecting potential hazards such as floating logs and old nets, and assisting resource users.

The corporation celebrated National Aboriginal Awareness Week in May 2012 with culturally significant activities including musical performances by Aboriginal employees of Manitoba Hydro and teepee teachings from an Aboriginal elder. In addition, over 1 700 employees have participated in Aboriginal cultural awareness workshops since the corporation began offering sessions in 2005.

Supporting communities

In June 2012, eight students representing the first Canadian class of Project Search graduated from high school during a ceremony at Manitoba Hydro Place. Project Search partnered with Manitoba Hydro to provide high school students with an intellectual disability the opportunity to gain employability skills. The 10-month program included class time at Manitoba Hydro combined with a variety of work experience placements. Students are given support through work accommodations and adaptations as well as on-the-job coaching provided by the Project Search Program. Year two of the program began in September 2012.

Manitoba Hydro was a sponsor of the 55Plus Games held in Arborg from June 12 to 14. The event attracted nearly 900 participants competing in events such as bowling, contract bridge, darts, golf, baseball and track. Organized by the Active Living Coalition for Older Adults in Manitoba, the games promote the benefits of healthy living for older Manitobans and provide opportunities for regular physical, mental and social activities. The corporation has also agreed to sponsor the 2013 games to be held in Morris.

The corporation also sponsored a number of other community events in 2012-13 including the Power Smart Santa Claus Parade in Winnipeg, the Power Smart Manitoba Games in Swan River and the Northern Manitoba Trapper's Festival in The Pas.

Corporate governance

The affairs of Manitoba Hydro are overseen by a board whose members are appointed by the Lieutenant-Governor in Council of Manitoba.

The board's primary responsibility is to ensure that the corporation carries out its legislative mandate. The board considers the principles of sustainable development, and Manitoba Hydro's code of ethics, in its decisions. Minutes of board meetings are public and the corporation's annual report and quarterly financial statements are tabled in the legislature. The annual report is approved by a committee of the Manitoba legislature. The mandate of the corporation is reviewed by the Crown Corporations Council.

The Audit Committee of the board reviews Manitoba Hydro's integrated financial forecast and makes recommendations to the board. The Audit Committee reviews whether Manitoba Hydro's quarterly and annual financial statements present fairly the financial position and performance in accordance with generally accepted accounting principles. The Audit Committee confirms whether management has assessed areas of potential significant financial and operational risk and has taken appropriate measures, and the Audit Committee reviews management's systems for ensuring legal compliance. The Audit Committee obtains opinions from external auditors, internal auditors and management on the quality of internal controls, and verifies that external auditors have performed their duties with sufficient independence from management.

The Human Resources and Governance Committee assists the board with succession planning and human resources issues. The committee reviews the board's approach to corporate governance with a view to best practices and Manitoba Hydro's mandate.

All of the members of the board sit on the Planning Committee, which approves the annual corporate strategic plan.

Integrity Program

Manitoba Hydro encourages employees and others to speak up on matters of concern without fear of reprisal, through its Integrity Program. All disclosures under the Integrity Program are protected by strict rules of confidentiality.

Below is a summary of all disclosures received during 2012-13 which allege wrongdoing as defined in The Public Interest Disclosure (Whistleblower Protection) Act:

Total number of disclosures received:	22
Number of disclosures ongoing from 2011-12:	4
Number of disclosures acted upon:	26
Number of disclosures not acted upon:	0
Number of investigations commenced/continued:	26
Number of disclosures that were verified:	5
Number of disclosures that were investigated and could not be verified:	11
Number of disclosures carried forward to 2013-14:	10

Corrective action was taken for each verified incident, as follows:

- Two employees were terminated for a conflict of interest.
- One employee was terminated and one employee received a written reprimand for mismanagement at a work site.
- An employee was terminated for falsifying a mileage claim.
- An employee received a five-day suspension for submitting and entering false information into the corporation's records.
- An employee received a three-day suspension for making unwanted sexual advances and comments.

Manitoba Hydro-Electric Board

Appearing left to right:

Carmen Neufeld

Dr. John Loxley

Tina Keeper

Eugene Kostyra

William C. Fraser, FCA
Chair

David Crate

Larry Vickar

Dudley Thompson

James Husiak, CA

Not in photo:
Michael Spence, Frank Whitehead

Manitoba Hydro Senior Officers

Appearing left to right:

Ed T. Tymofichuk, P. Eng
Vice-President, Transmission

Ken M. Tennenhouse, LL.B
Vice-President, General Counsel and Corporate Secretary

Darren B. Rainkie, CA, CBV
Vice-President, Finance and Regulatory

Lloyd Kuczek, P. Eng, MBA
Vice-President, Customer Care & Energy Conservation

Scott A. Thomson, CA
President and Chief Executive Officer

E. Ruth Kristjanson, BA (Hons), MA
Vice-President, Corporate Relations

Ken R. F. Adams, P. Eng
Senior Vice-President, Power Supply

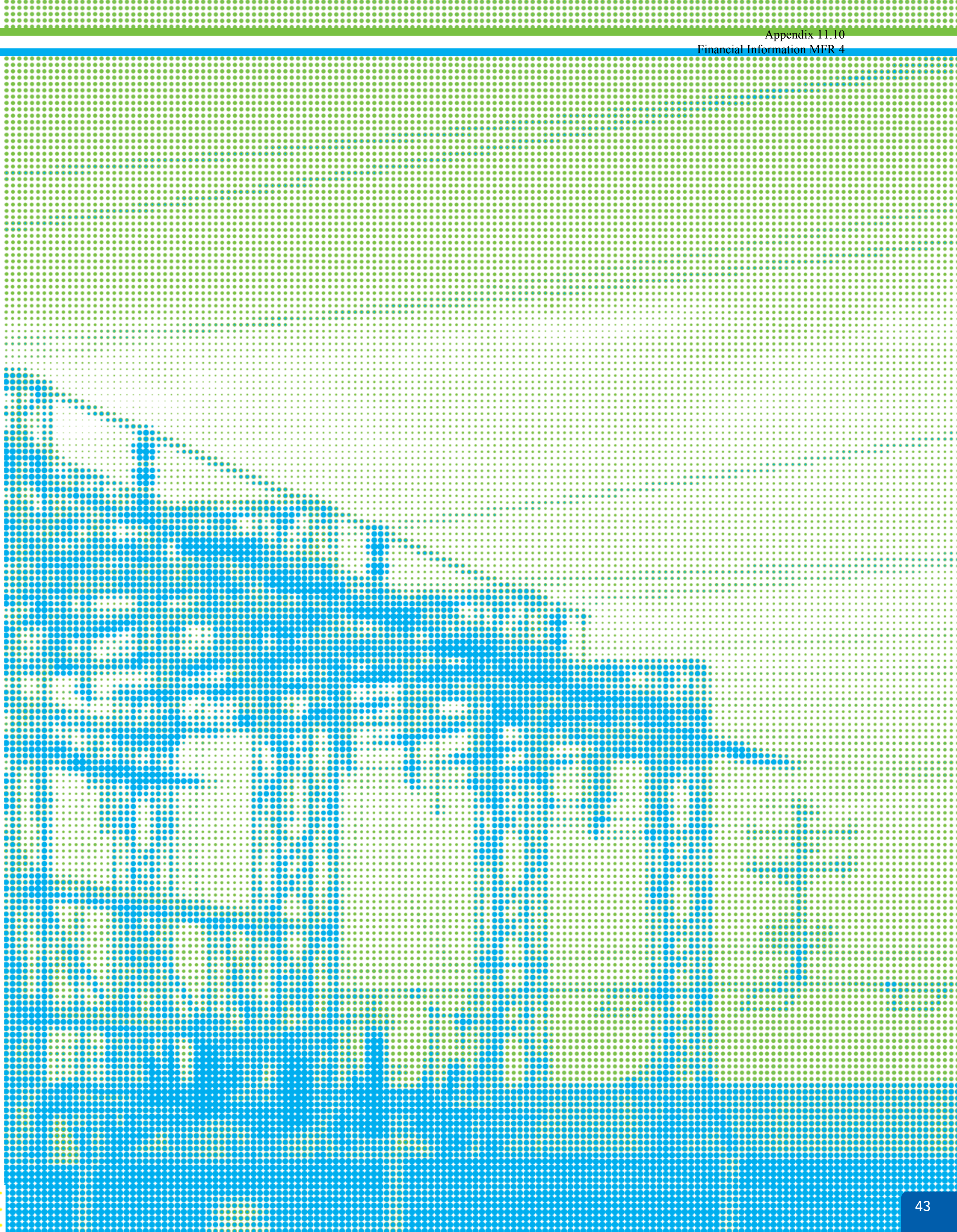
G. Brent Reed
Vice-President, Customer Care and Distribution

Bryan Luce
Vice-President, Human Resources and Corporate Services

Financial Review

Management's Discussion and Analysis

Consolidated Financial Statements



The Management's Discussion and Analysis (MD&A) section of the Annual Report provides comments on the financial results and operational performance of Manitoba Hydro for the year ended March 31, 2013 with comparative information where applicable. The MD&A also provides an assessment of Corporate risks and contains forward-looking statements regarding conditions and events which may affect financial performance in the future. Such forward-looking statements are subject to a number of uncertainties which are likely to cause actual results to differ from those anticipated. For context, the MD&A should be read in conjunction with the consolidated financial statements and notes.

As a provincially-owned Crown Corporation, Manitoba Hydro's mandate is to provide for the continuance of a supply of energy to meet the needs of Manitoba consumers in the most reliable, economic and environmentally sustainable manner. In fulfilling its mandate, Manitoba Hydro has assessed all known risks and has established a number of goals with related measures and targets. In addition to a review of financial and operational performance, the MD&A also reviews Manitoba Hydro's progress towards achieving its strategic goals.

OVERVIEW

Manitoba Hydro's consolidated net income from electricity and natural gas operations for the fiscal year ended March 31, 2013 was $92 million compared to $61 million in the previous fiscal year. The increase in net income of $31 million was largely attributable to increased revenues from domestic electricity sales partially offset by higher expenses. The Wuskwatim Generating Station became operational during 2012-13 which also contributed to higher expenses over the previous year.

Consolidated net income of $92 million for the 2013 fiscal year was comprised of net income of $84 million in the electricity sector and net income of $8 million in the natural gas sector. The gas sector net income represented a $14 million improvement over the previous year which was mainly a result of colder weather during the winter of 2012-13 compared to warmer weather during the winter of 2011-12.

Consolidated net income of $92 million for 2012-13 was higher than the forecasted net income of $60 million largely due to higher than forecast electricity revenues and lower than forecast power purchases.

Net income of $92 million contributed to the Corporation's retained earnings of $2 542 million at March 31, 2013, the highest level of equity in the Corporation's history. The debt to equity and capital coverage ratios met or exceeded target levels while the interest coverage ratio was close to the target level for the year.

CONSOLIDATED RESULTS

The following schedule summarizes Manitoba Hydro's consolidated financial results for the fiscal year ended March 31, 2013 compared to the previous fiscal year:

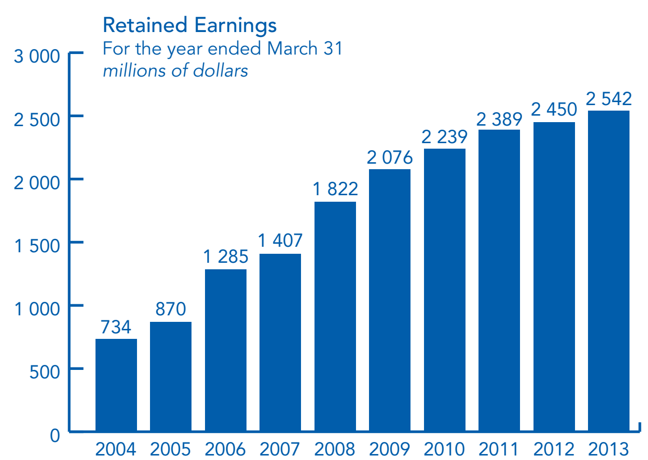
	Electricity		Natural Gas		Consolidated		
	2013	2012	2013	2012	2013	2012	Change
	millions of dollars						
Revenues							
Manitoba (net of cost of gas sold)	1 380	1 219	147	132	1 527	1 351	176
Extraprovincial	353	363	-	-	353	363	(10)
	1 733	1 582	147	132	1 880	1 714	166
Expenses	1 662	1 515	139	138	1 801	1 653	148
Net income (loss) before non-controlling interest	71	67	8	(6)	79	61	18
Net loss attributable to non-controlling interest	13	-	-	-	13	-	13
Net income (loss)	84	67	8	(6)	92	61	31
Total assets	13 928	13 203	614	588	14 542	13 791	751
Retained earnings	2 500	2 416	42	34	2 542	2 450	92
Financial Ratios							
Debt:Equity					75:25	74:26	
Interest coverage					1.15	1.10	
Capital coverage					1.25	1.13	

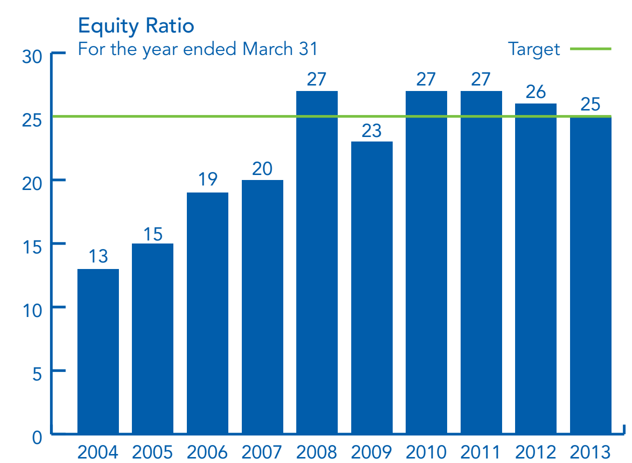
Revenues from consolidated electricity and natural gas operations totaled $2 062 million in 2012-13 compared to $1 911 million in the previous fiscal year. After deducting the cost of gas sold, which is a pass-through cost with no mark-up to customers by Manitoba Hydro, revenues amounted to $1 880 million compared to $1 714 million in the prior year. The $166 million or 9.7% increase in revenues was largely attributable to increased domestic electricity sales as a result of increases in electricity rates and colder weather than the previous year.

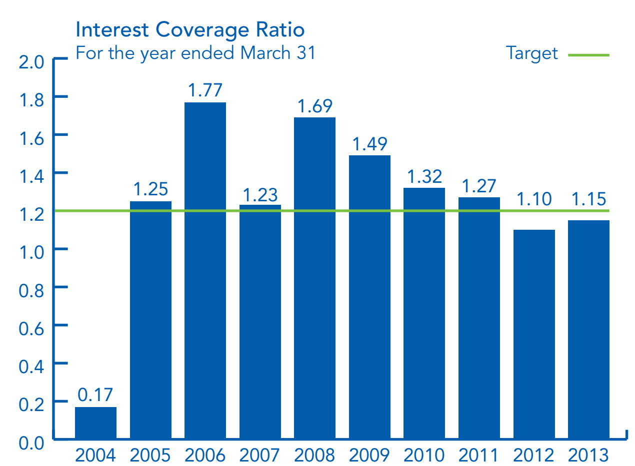
Expenses for electricity and natural gas operations totaled $1 801 million in 2012-13, an increase of $148 million or 8.9% over the previous year. The increase was largely due to a $66 million increase in finance expense, a $52 million increase in operating and administrative expense and a $42 million increase in depreciation and amortization partially offset by a $13 million decrease in power purchases.

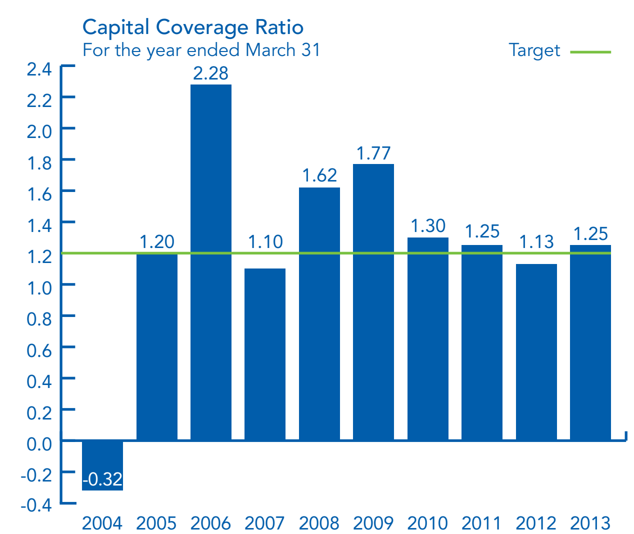
Net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's (TPC) 33% share of the Wuskwatim Power Limited Partnership's (WPLP) operating loss of $40 million in 2012-13. The WPLP has two limited partners, Manitoba Hydro and TPC, which is owned beneficially by Nisichawayasihk Cree Nation (NCN), and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro.

Net income from electricity and natural gas operations amounted to $92 million in 2012-13 compared to $61 million in the previous year. The consolidated net income increased retained earnings to $2 542 million at March 31, 2013. As indicated in the accompanying chart, net income of $92 million resulted in the equity ratio being 25% at March 31, 2013, which is consistent with the Corporation's target of 25%. The capital coverage ratio of 1.25 exceeded the target of 1.20 and the interest coverage ratio of 1.15 was slightly lower than the target of 1.20.









Financing

Cash provided from operations in 2012-13 was $589 million, an increase of $22 million from the previous year. The increase reflects higher net income than the previous year.

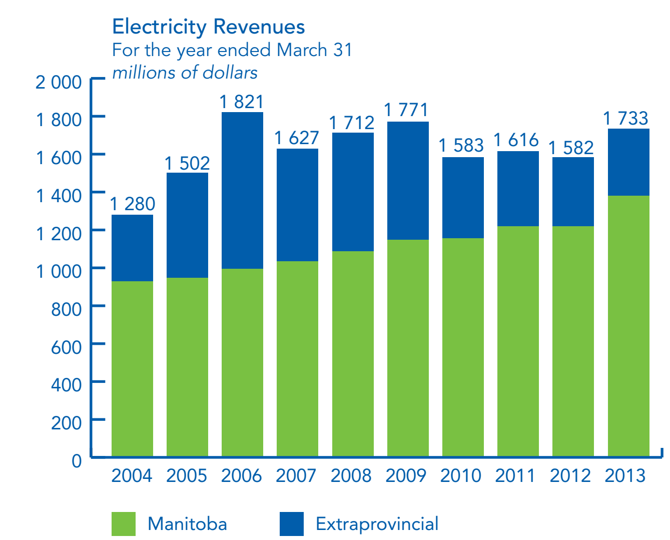
Proceeds from financing arranged by the Corporation amounted to $807 million in 2012-13 compared to $698 million in the previous year. Current year proceeds were used to fund new capital requirements and to retire long-term debt maturing during the year.

During 2012-13, the Corporation retired $242 million of debt comprised of Provincial Advances of $150 million, HydroBonds of $81 million and Manitoba Hydro-Electric Board Bonds of $11 million.

ELECTRICITY OPERATIONS

Electricity Revenues

Electricity revenues totaled $1 733 million, an increase of $151 million or 9.5% from the previous year. The increase was the result of a $161 million increase in domestic revenues partially offset by a $10 million decrease in extraprovincial revenues. The increase in domestic revenues was primarily due to rate increases and higher usage as a result of colder weather during the winter heating season. The decrease in extraprovincial revenues was primarily due to lower volumes in the U.S. markets.



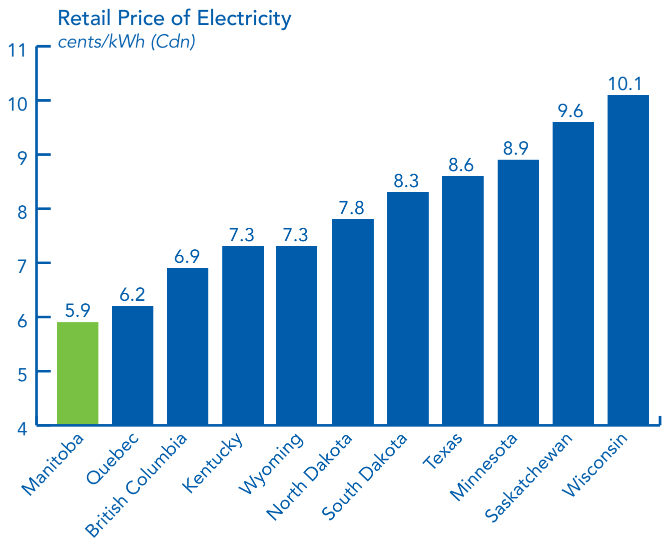
Electricity Rates

In Order 43/13, dated April 26, 2013, the Public Utilities Board (PUB) provided final approval of the 2.0% and the 2.4% rate increases that had been approved on an interim basis effective April 1, 2012 and September 1, 2012, respectively.

The PUB had directed in Order 5/12, dated January 17, 2012, that the 2.9% electricity rate increase previously approved on an interim basis effective April 1, 2010 be reduced to 1.9% and that the associated revenues were to be set aside as a regulatory deferral until further direction was provided by the PUB. The cumulative impact of the 1.0% rate reduction for 2010-11 and 2011-12 was recorded as a reduction to revenues of $23 million in 2011-12. In Order 43/13, the PUB approved the Corporation's application to reinstate the 1.0% rate deferral as revenue in the 2012-13 fiscal year. The cumulative impact of this decision was to increase revenues by $35 million in 2012-13 of which $23 million related to 2010-11 and 2011-12.

Management's Discussion and Analysis

Manitoba Hydro's domestic electricity rates continue to be the lowest overall in North America. This is illustrated in the chart below which was excerpted from utilities' annual reports and United States Department of Energy and Edison Electric Institute publications.

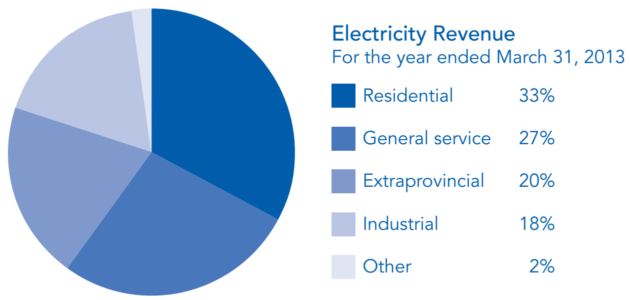


The breakdown of electricity revenues by customer segment is as follows:

Electricity Revenues and Kilowatt Hour Sales
For the year ended March 31

	2013	2012	% change	2013	2012	% change
	millions of dollars			*millions of kWh*		
Manitoba						
Residential	554	501	10.6	7 334	6 930	5.8
General service	465	432	7.6	6 877	6 660	3.3
Industrial	299	283	5.7	7 266	7 180	1.2
Other revenue	39	26	50.0	-	-	-
	1 357	1 242	9.3	21 477	20 770	3.4
1% rate deferral	23	(23)	-	-	-	-
Manitoba revenue	1 380	1 219	13.2	21 477	20 770	3.4
Extraprovincial	353	363	(2.8)	9 087	10 244	(11.3)
	1 733	1 582	9.5	30 564	31 014	(1.5)

Revenues from electricity sales in Manitoba totaled $1 380 million in 2012-13, an increase of $161 million from the previous year. Electricity consumption in Manitoba was 21 477 million kilowatt-hours, 707 million kilowatt-hours higher than the previous year. The increase in consumption was mainly due to higher heating loads as a result of colder winter weather in 2012-13.



Revenues from sales to residential customers for 2012-13 amounted to $554 million, an increase of $53 million or 10.6% from the previous year. The increase was primarily a result of a higher heating load from colder winter weather and the rate increases implemented during the year. At March 31, 2013 the number of residential customers was 480 254, an increase of 5 593 or 1.2% compared to the previous year.

Revenues from general service customers amounted to $465 million in 2012-13, an increase of $33 million or 7.6% from the previous year. The increase was mainly attributable to the rate increases implemented during the year, colder winter weather and an increase of 488 customers.

Revenues from large industrial customers amounted to $299 million, an increase of 5.7% or $16 million from the previous year. The increase was mainly the result of rate increases implemented during the year and increased consumption.

Extraprovincial revenues totaled $353 million in 2012-13, a decrease of $10 million from the previous year. The decrease reflects lower U.S. and Canadian sales volumes resulting from increased Manitoba load partially offset by higher export prices. Of the total extraprovincial revenues, $312 million or 88% was derived from the U.S. market, while $41 million or 12% was from sales to Canadian markets.

Electricity Expenses

Electricity expenses totaled $1 662 million for 2012-13, an increase of $147 million or 9.7% over the previous year. The increase in expenses was primarily the result of a $67 million increase in finance expense, a $50 million increase in operating and administrative expenses, a $41 million increase in depreciation and amortization partially offset by a $13 million decrease in power purchases.

Electricity Expenses
For the year ended March 31

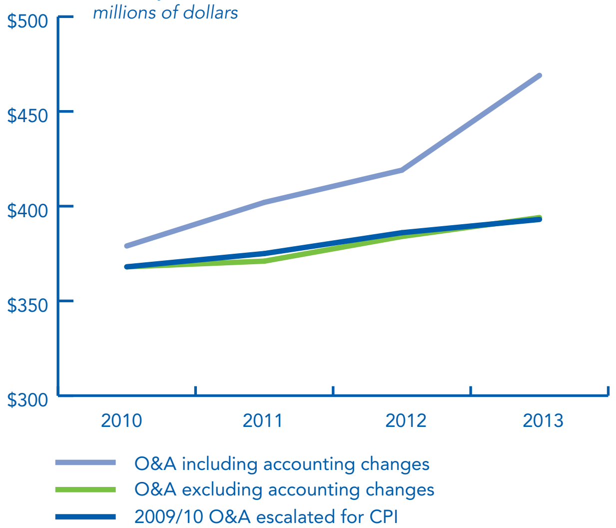
	2013	2012	% change
	millions of dollars		
Operating and administrative	469	419	11.9
Finance expense	452	385	17.4
Depreciation and amortization	394	353	11.6
Water rentals and assessments	118	119	(0.8)
Fuel and power purchased	133	146	(8.9)
Capital and other taxes	87	84	3.6
Corporate allocation	9	9	-
	1 662	1 515	9.7

Management's Discussion and Analysis

Operating and administrative expenses are comprised primarily of labour, material and overhead costs associated with operating, maintaining and administering the facilities and programs of the Corporation. In 2012-13, operating and administrative expenses for electric operations amounted to $469 million, an increase of $50 million over 2011-12. The increase in operating and administrative expenses attributable to accounting changes implemented during the year was $30 million and the increase in employee benefits resulting from changes in discount rates was $12 million. After adjusting for these accounting and discount rate changes, the increase in operating and administrative expenses for 2012-13 was $8 million or 1.9% as compared to the previous year.

The following graph provides a comparison of the growth in operating and administrative expenses, including and excluding accounting changes, as compared to changes in the consumer price index (CPI). This demonstrates that when excluding accounting changes Manitoba Hydro has managed its operating and administrative expenses consistent with inflation even with the in-service of the Wuskwatim generating station.

Operating & Administrative Expenses
For the year ended March 31
millions of dollars



Finance expense totaled $452 million in 2012-13, an increase of $67 million or 17.4% from the previous year. The increase was primarily due to higher volumes of long-term debt to finance capital expenditures, the financing costs associated with the Wuskwatim Generating Station coming into service during the year and a weaker Canadian dollar.

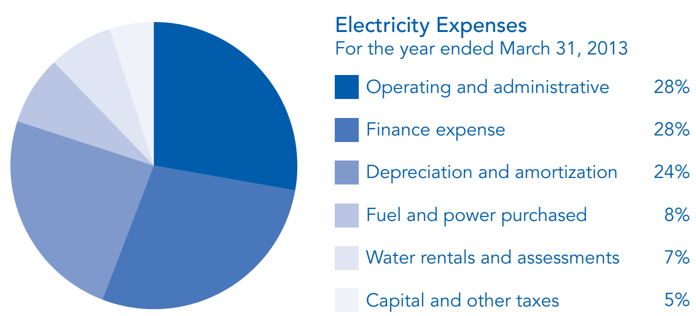
Depreciation and amortization expense amounted to $394 million in 2012-13, an increase of $41 million or 11.6% from the previous year. The increase was mainly attributable to new additions to plant and equipment coming into service, including the Wuskwatim Generating Station.

Water rentals and assessments amounted to $118 million in 2012-13, a decrease of $1 million from the previous year. The decrease reflects a small reduction in other fees and assessments. Hydraulic generation amounted to 33.1 billion kilowatt-hours in 2012-13 which is the same as 2011-12.

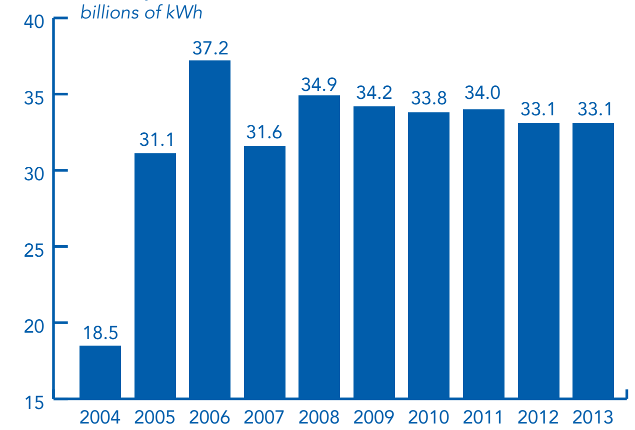
Fuel and power purchased includes fuel for the thermal generating stations and remote diesel sites, purchases of wind power from the independently-owned St. Leon and St. Joseph wind farms and from electricity imports. Fuel and power purchased was $133 million in 2012-13, a decrease of $13 million or 8.9% over 2011-12. The decrease in power purchased was primarily the result of lower system merchant purchases due to reduced arbitrage opportunities between markets and credits received on transmission rights due to higher than expected congestion.

Capital and other taxes amounted to $87 million in 2012-13, an increase of $3 million or 3.6% compared to the previous year. The change was mainly due to increased capital taxes related to additional capital investment.

Electricity Expenses
For the year ended March 31, 2013



Hydraulic Generation
For the year ended March 31
billions of kWh

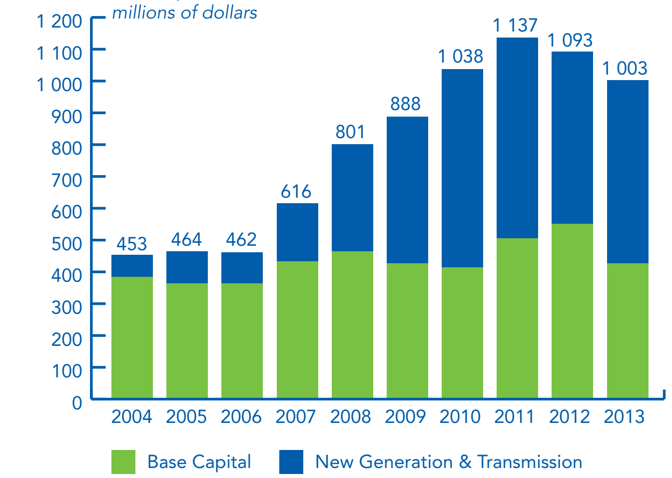


Electricity Capital Expenditures

Expenditures for capital construction totaled $1 003 million in 2012-13 compared to $1 093 million during the previous fiscal year. Capital expenditures for ongoing plant and equipment requirements, referred to as base capital, amounted to $429 million, a decrease of $124 million compared to the previous year. The decrease was attributable to lower expenditures on generation and substation upgrades.

Major new generation and transmission capital expenditures of $574 million included $169 million related to future Keeyask and Conawapa generation facilities, $109 million related to the Bipole III project, $101 million towards the Pointe du Bois Spillway replacement and station rehabilitation, $84 million for the Riel Station, $78 million related to the Wuskwatim Generating Station and transmission line and $28 million for upgrades to the Kelsey Generating Station.

Electricity Capital Expenditures
For the year ended March 31
millions of dollars



NATURAL GAS OPERATIONS

Centra Gas Manitoba Inc. (Centra) is a wholly-owned subsidiary of Manitoba Hydro. Centra distributes natural gas to 244 768 residential and 25 018 commercial and industrial customers in Manitoba.

Net income in the gas sector was $8 million in 2012-13 compared to a net loss of $6 million in the previous fiscal year. The improved financial performance over the previous year was primarily attributable to increased demand due to colder weather during the winter of 2012-13 compared to warmer weather during the winter of 2011-12.

Natural Gas Revenues

Revenues from the sale and distribution of natural gas during 2012-13 were $329 million, consistent with the previous year. After deducting the cost

of gas sold, which is a pass-through cost with no mark-up by Centra, net revenues amounted to $147 million, an increase of $15 million from 2011-12. The increase in net revenue was almost entirely due to colder winter weather than the previous year. Natural gas deliveries were 2 049 million cubic metres in 2012-13 compared to 1 866 million cubic metres in 2011-12.

As directed by the PUB, $3.8 million of revenue from 2012-13 was set aside to continue a program targeted to low-income customers and qualifying seniors on fixed incomes to assist in the replacement of low efficiency furnaces with high efficiency furnaces. At March 31, 2013, there is a remaining balance of $16 million in the Furnace Replacement Program.

Natural Gas Revenues and Deliveries

For the year ended March 31

	2013	2012	% change	2013	2012	% change
	millions of dollars			*millions of cubic metres*		
Residential	174	172	1.2	602	509	18.3
Small general service	25	23	8.7	100	81	23.5
Large general service	95	96	(1.0)	523	440	18.9
Large commercial & industrial	18	20	(10.0)	133	121	9.9
Interruptible	11	12	(8.3)	93	86	8.1
T-service and other	6	6	-	598	629	(4.9)
	329	329	-	2 049	1 866	9.8

Natural Gas Rates

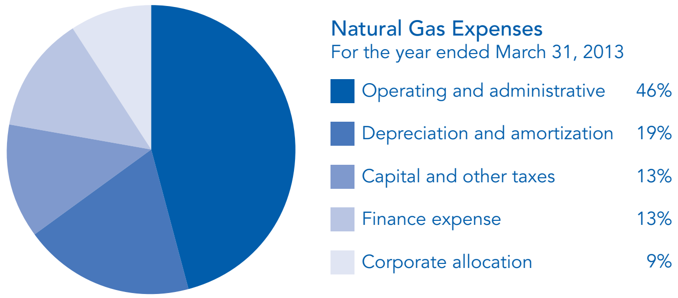
In accordance with Centra's quarterly rate-setting methodology, annualized rates for natural gas supplied to residential customers changed during 2012-13 as follows:

- May 1, 2012 — 8.6% decrease
- August 1, 2012 — 2.9% increase
- November 1, 2012 — unchanged
- February 1, 2013 — unchanged

The change in natural gas rates reflects the fluctuations in pricing for natural gas purchased by Centra. Centra did not apply to the PUB for a general rate increase related to non-gas costs in 2012-13.

Natural Gas Expenses

Expenses attributable to the natural gas operations, excluding cost of gas sold, amounted to $139 million in 2012-13, which was $1 million higher than the previous year. Increases of $2 million in operating and administrative expenses and $1 million in depreciation and amortization were partially offset by decreases of $1 million in each of finance expense and capital and other taxes.



Natural Gas Expenses

For the year ended March 31

	2013	2012	% change
	millions of dollars		
Operating and administrative	64	62	3.2
Finance expense	18	19	(5.3)
Depreciation and amortization	27	26	3.8
Capital and other taxes	18	19	(5.3)
Corporate allocation	12	12	-
	139	138	0.7

Centra purchased 493 million cubic metres of natural gas based on monthly Alberta indexed pricing, 235 million cubic metres under daily Alberta indexed pricing and 394 million cubic meters from a number of other supply sources. Centra also delivered natural gas on behalf of brokers to 17 418 (2012 – 17 965) customers receiving natural gas under Direct Purchase arrangements.

Centra offers a fixed rate service for primary natural gas supply which allows customers to fix their natural gas rates for terms of up to five years. The fixed rate service is offered to residential and commercial customers. At March 31, 2013 there were 396 customers (2012 – 434 customers) on Centra's fixed rate service. Total natural gas deliveries under this service were 6.0 million cubic metres (2012 – 4.0 million cubic metres).

Natural Gas Capital Expenditures

Capital expenditures in the natural gas sector were $34 million in 2012-13 compared to $31 million in the previous fiscal year. The capital expenditure program relates to new business, system improvement and other expenditures to meet the needs of the natural gas customers.

SUBSIDIARIES

In addition to Centra, Manitoba Hydro has the following wholly-owned subsidiaries involved in energy-related business enterprises:

Manitoba Hydro International Ltd. (MHI) provides professional consulting, operations, maintenance and project management services to energy sectors world-wide, either exclusively or through partnerships. MHI also provides research and development services and products to the electrical power system industry.

Manitoba Hydro Utility Services Ltd. (MHUS) provides meter reading and related services to Manitoba Hydro, Centra and other utilities.

The following table provides a summary of the financial results of the subsidiary companies excluding Centra for the fiscal year ended March 31, 2013 compared to the previous fiscal year:

	MHI		MHUS		Other		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
				millions of dollars				
Revenues	43.2	31.8	4.6	5.5	1.1	0.8	48.9	38.1
Expenses	38.2	27.9	4.6	5.1	0.2	0.2	43.0	33.2
Net income	5.0	3.9	-	0.4	0.9	0.6	5.9	4.9

WUSKWATIM POWER LIMITED PARTNERSHIP

The WPLP was formed to carry on the business of developing, owning and operating the Wuskwatim Generating Station and related works, excluding the transmission facilities but including all dams, dikes, channels, excavations and roads. The WPLP has two limited partners, Manitoba Hydro and TPC, which is owned beneficially by NCN, and a General Partner which is a wholly-owned subsidiary of Manitoba Hydro. The Wuskwatim Generating Station is located at Taskinigahp Falls on the Burntwood River approximately 45 kilometres southwest of Thompson, Manitoba.

During 2012-13, power production started at the Wuskwatim Generating Station. The first of three generating units was placed in service on June 22, 2012, the second unit on August 22, 2012 and the third unit on October 6, 2012. The WPLP reported a net loss for 2012-13 of $40 million which was consistent with expectations for the first year of operation. Manitoba Hydro's 67% share of the loss was $27 million and TPC's 33% share of the loss was $13 million. At March 31, 2013 total assets for Wuskwatim generation and transmission facilities amounted to $1.6 billion (2012 – $1.6 billion).

CORPORATE GOALS

Manitoba Hydro has the following Corporate goals:

Improve safety in the workplace
Achieving an accident-free workplace is Manitoba Hydro's most important goal and a critical component of all Corporate activities. Manitoba Hydro is committed to continuously improving its safety performance and is currently focusing on strategies that will eliminate all high-risk incidents and further instill a safety and health culture throughout the Corporation.

Provide exceptional customer value
Manitoba Hydro continually strives to provide exceptional value to customers through low energy rates, a safe and secure system, high reliability and superior service.

Strengthen working relationships with Aboriginal communities
Manitoba Hydro is one of the leading utilities in Canada with respect to Aboriginal representation in its workforce. The Corporation continues to place emphasis on building enduring working relationships with Aboriginal communities through such measures as pre-employment training programs, purchasing and employment preferences, support for Aboriginal businesses and recognition of cultural requirements in the workplace.

Maintain financial strength
Maintaining the financial strength of the Corporation will ensure that energy rates remain low, stable and predictable. A strong financial structure also assists in protecting the Corporation and its customers from a variety of risks.

Extend and protect access to North American energy markets and profitable export sales
The ability to sell surplus energy into export markets has contributed significantly to low domestic rates in Manitoba. It is important that access to profitable export markets be maintained and expanded.

Attract, develop and retain a highly skilled and motivated workforce that reflects the demographics of Manitoba
In the increasingly competitive marketplace for talented people, Manitoba Hydro must continue to attract and retain the very best in human resources while striving to attain its diversity targets.

Protect the environment in everything that we do
Manitoba Hydro is dedicated to upholding the principles of sustainable development and to preventing or mitigating any adverse impacts from our operations. Through careful management of new and existing facilities and infrastructure, Manitoba Hydro continues to operate in the most environmentally responsible manner.

Promote cost effective energy conservation and innovation
Manitoba Hydro is recognized as a Canadian leader in promoting the wise and efficient use of energy through its Power Smart brand and continues to encourage research and development of emerging energy technologies.

Be recognized as an outstanding corporate citizen and a driver of economic development in Manitoba
Manitoba Hydro and its employees continue to take leadership roles in community activities and programs throughout the province. The Corporation also works with economic development agencies to maximize wealth and jobs in Manitoba and works with customers to minimize their energy costs.

REPORT ON PERFORMANCE

The following table summarizes the progress the Corporation is making towards achieving its Corporate goals:

Goal	Measure	Target / Challenge	2013 Performance
Safety in the Workplace	High-risk incidents	0	0
	Accident severity rate (days per 200 000 hours worked)	<12	9.7
	Accident frequency rate (accidents per 200 000 hours worked)	<0.6	0.7
Exceptional Customer Value	Retail electricity rates (overall)	Lowest in North America	Lowest in North America
	System average interruption duration (minutes per year)	<113	175
	Average electric customer outage frequency (outages per year)	<1.4	1.9
	CEA Customer Service Index	Best in Canada	Ranked 2nd
Financial Strength	Debt:Equity Ratio	75:25	75:25
	Interest Coverage	>1.20	1.15
	Capital Coverage	>1.20	1.25
Diverse Work Force	Women	26%	25%
	Aboriginal – Corporate	16%	17%
	Aboriginal – Northern	45%	42%
	Persons with disabilities	6%	10%
	Visible minorities	7%	7%
Protecting the Environment	% Generation from renewable resources	>99%	99.9%
Sustainability & Energy Conservation	Electric energy saved per year	2 069 GWh	2 187 GWh
Corporate Citizenship & Economic Development	CEA Public Attitude Index	≥8.5	7.8
	Corporate Citizenship Index	≥8.2	7.6

RISK MANAGEMENT

Manitoba Hydro faces a number of risks in the fulfillment of its mandate. These risks are managed through a systematic, proactive and integrated process designed to balance the objectives of:

- identifying threats that affect the achievement of the Corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on preventing or reducing the likelihood of the occurrence of negative events. However, the Corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or natural disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, aging infrastructure maintenance and replacement, increasing regulatory, environmental and legal requirements and accelerated technological change. Manitoba Hydro manages these risks through an integrated control framework and through the maintenance of an adequate level of retained earnings.

Manitoba Hydro's major risks are quantified in the following table:

Risk	Potential Financial Impact
Infrastructure	Greater than $2.0 billion
Drought	Greater than $1.6 billion for a five year drought
Loss of export market	Greater than 30% of electricity revenue
Interest rates	Approximately $700 million for a 1% change over 10 years

STATUS OF TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In September 2012 and February 2013, the Canadian Accounting Standards Board (AcSB) announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Manitoba Hydro meets the AcSB criteria for deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

The Corporation expects the transition to IFRS to impact accounting, financial reporting and related information systems. To facilitate the conversion process, Manitoba Hydro has assembled a project team, engaged external advisors and established a formal project governance structure with the formation of a Steering Committee consisting of an executive sponsor and senior levels of management from throughout the Corporation. Regular reporting of the project status is provided to the Audit Committee of the Manitoba Hydro-Electric Board.

Although IFRS and Canadian Generally Accepted Accounting Principles (GAAP) are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Manitoba Hydro include property, plant and equipment, regulatory assets and liabilities, employee benefits and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

On April 25, 2013, the International Accounting Standards Board (IASB) issued the Exposure Draft - Regulatory Deferral Accounts. The Exposure Draft proposes an interim standard intended to allow entities that are first–time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. Under the proposed interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. Comments on the Exposure Draft are due in September of 2013 and the IASB is not expected to make a decision on the proposed interim standard until December of 2013.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in changes to existing IFRS prior to the commencement of Manitoba Hydro's 2015-16 fiscal year. Manitoba Hydro continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

Management's Discussion and Analysis

OUTLOOK

Manitoba Hydro ended fiscal 2012-13 with above average water storage levels. Inflows from spring runoff for 2013-14 are expected to be average, particularly in the Red, Assiniboine and Saskatchewan River basins. Manitoba Hydro experienced some year-over-year recovery to export market prices through the fourth quarter of 2012-13 largely a result of higher natural gas prices and improved economic conditions in the U.S. Based on current conditions and considering the impact on expenses of the Wuskwatim Generating Station being in-service for a full year, Manitoba Hydro expects its net income for 2013-14 to be below the level experienced in 2012-13.

Manitoba Hydro is actively planning a number of major projects such as the Bipole III transmission line and Keeyask and Conawapa generating stations in order to further improve electrical system reliability, to meet the future energy needs of the province and to take advantage of export opportunities. These plans will involve the investment of approximately $20 billion over the next 10 years which will generate significant returns for Manitobans over ensuing decades. Construction of the new generating stations will only proceed once firm export sales contracts are secured, extensive consultations with stakeholders and First Nations are concluded and environmental and regulatory approvals are received.

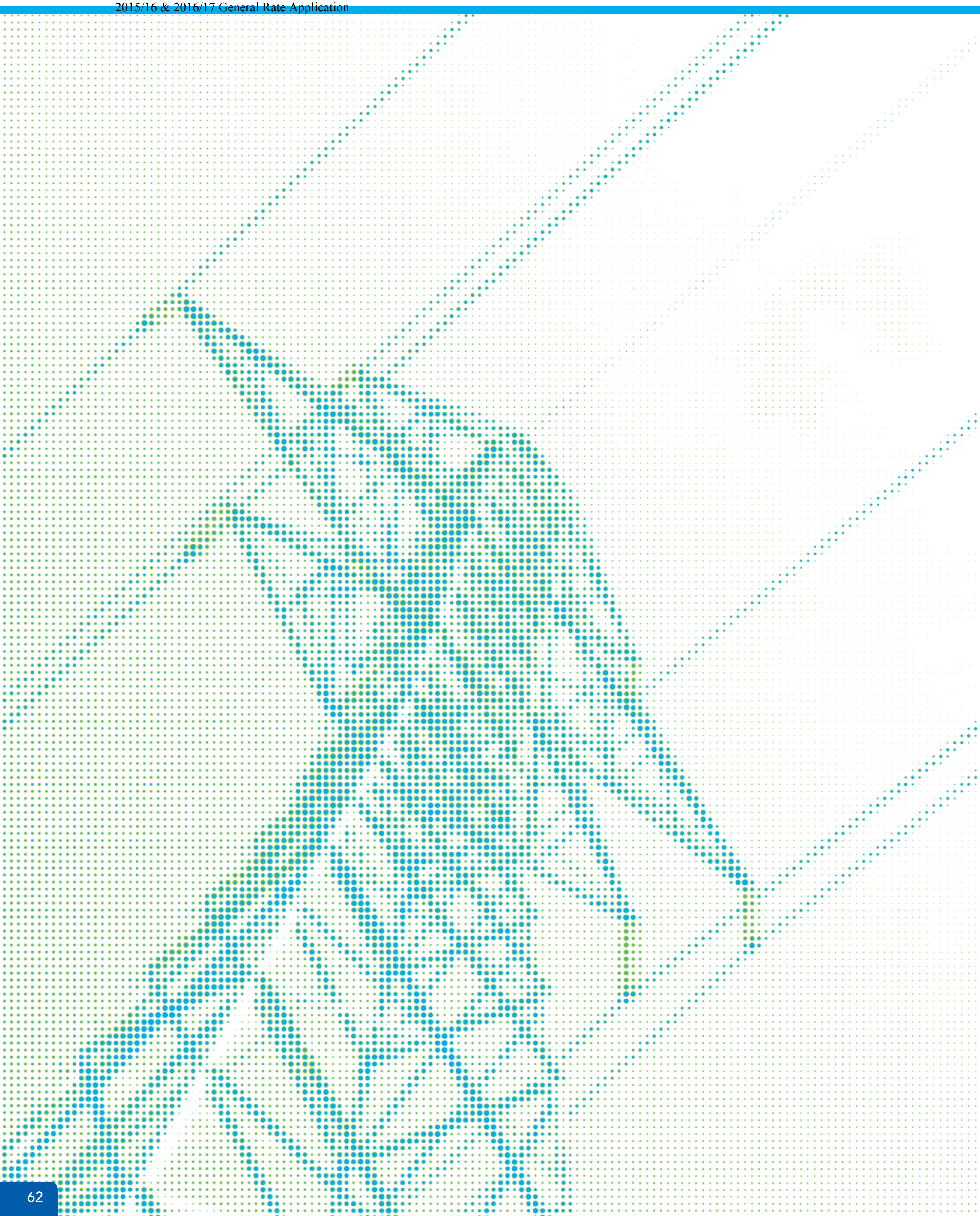
The Bipole III project involves the construction of a new 500-kV high voltage direct current transmission line along with new converter stations, one in the north and another at the southern receiving end. The project is required to improve system reliability and will also provide additional capacity for delivery of existing and proposed hydro-electric generation to southern markets. The Environmental Impact Statement related to Bipole III was filed with Manitoba Conservation in December 2011. Public hearings on the project by the Clean Environment Commission began in the fall of 2012 and concluded in early 2013 with an environmental licensing decision pending. Construction is scheduled to begin, pending regulatory approval, in the winter of 2013-14 with a scheduled in-service date of late 2017.

The proposed 695-megawatt Keeyask Generating Station would be built on the Nelson River, 30 kilometres west of Gillam, within the Split Lake Resource Management Area, in partnership with four Keeyask Cree Nations (KCN) – Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. A Keeyask Infrastructure Agreement was negotiated between Manitoba Hydro and KCN enabling an early start to the construction of the access road to the site and the construction camp. The project description was filed with the federal Major Projects Management Office in July 2011 and the Environmental Act Proposal form was filed with Manitoba Conservation in December 2011. The application for the Keeyask Project Interim Water Power License was submitted to the Province in early 2012. The Environmental Impact Statement was filed in July 2012. The Manitoba Clean Environment Commission will hold hearings commencing in late September 2013. Work is progressing on maintaining the current regulatory schedule, with a construction start date of June 2014 and an expected in-service date of 2019.

The proposed 1 485-megawatt Conawapa Generating Station would be built approximately 90 kilometres downstream of Gillam and 28 kilometres downstream of the Limestone Generating Station, in the Fox Lake Resource Management Area on the Lower Nelson River. A formal planning process is underway with the communities in the vicinity of the project, including Fox Lake Cree Nation, York Factory First Nation, Tataskweyak Cree Nation, War Lake First Nation and Shamattawa First Nation. Activities are progressing to complete the Project Description, preliminary engineering and the environmental assessment and discussions on Aboriginal participation are beginning. The Environmental Impact Statement is scheduled to be filed by the end of 2014 with the potential start of construction in December 2016, which would support an earliest in-service date of 2025.

In accordance with Manitoba Order in Council No. 128/2013, a Needs For and Alternatives To review will be undertaken by the PUB of the economic justification for Manitoba Hydro's proposed development plan including Keeyask, Conawapa, a new Manitoba to U.S. transmission interconnection and new long-term export sales. The process will start with a filing by Manitoba Hydro in August 2013 with public hearings expected to commence in early 2014.

Manitoba Hydro's Power Smart Program continues to serve residential, commercial and industrial customers with a total of 28 programs and initiatives. The highly successful Power Smart Program continues to encourage all customer sectors to use energy more efficiently. These efforts work towards making permanent shifts in the Manitoba marketplace for long-term adoption of energy efficient technologies and practices. The Power Smart Program is projected to achieve electric energy and demand savings of 3 113 GWh per year and 846 MW by 2027-28. Natural gas savings are projected to be 126 million cubic metres per year by 2027-28. The overall Power Smart Program is expected to reduce greenhouse gas emissions by over 2.3 million tonnes annually while providing Manitobans with lower energy bills from the installation of energy savings measures and the continued sale of the conserved energy on export markets.



MANAGEMENT REPORT

For the year ended March 31, 2013

The accompanying consolidated financial statements and all additional information contained in the Annual Report are the responsibility of management and have been approved by the Manitoba Hydro-Electric Board. The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada, applied on a basis consistent with that of the preceding year. In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality, incorporating management's best judgment regarding all necessary estimates and all other data available up to June 26, 2013. The financial information presented elsewhere in the Annual Report is consistent with that in the consolidated financial statements.

Management maintains internal controls to provide reasonable assurance that the assets of the Corporation are properly safeguarded and that the financial information is reliable, timely and accurate. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its finding to management and to the Audit Committee of the Board.

The responsibility of the external auditors, Ernst & Young LLP, is to express an independent, professional opinion on whether the consolidated financial statements are fairly presented in accordance with Canadian generally accepted accounting principles. The Auditors' Report outlines the scope of their examination and their opinion.

The Audit Committee of the Board is comprised of five members, the majority of whom are members of the Manitoba Hydro-Electric Board. The Audit Committee of the Board meets with the external auditors, representatives of the Auditor General's Office, the internal auditors and management to satisfy itself that each group has properly discharged its respective responsibility and to review the consolidated financial statements before recommending approval by the Board. The internal and external auditors have full and unrestricted access to the Audit Committee, with or without the presence of management. The Board reviews the Annual Report in advance of its release and approves its content and authorizes its publication.

On behalf of management:

Scott A. Thomson, CA
President and Chief Executive Officer

Darren B. Rainkie, CA, CBV
Vice-President, Finance and Regulatory

Winnipeg, Canada
June 26, 2013

AUDITORS' REPORT

To the Board of Directors of
Manitoba Hydro-Electric Board

We have audited the accompanying consolidated financial statements of **Manitoba Hydro-Electric Board**, which comprise the consolidated balance sheet as at March 31, 2013 and the consolidated statements of income, comprehensive income, accumulated other comprehensive income, retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Manitoba Hydro-Electric Board** as at March 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants

Winnipeg, Canada,
June 26, 2013

CONSOLIDATED STATEMENT OF INCOME

For the year ended March 31

		Notes	2013	2012
			millions of dollars	
Revenues				
Electric	Manitoba		1 380	1 219
	Extraprovincial	3	353	363
Gas	Commodity		182	197
	Distribution		147	132
			2 062	1 911
Cost of gas sold			182	197
			1 880	1 714
Expenses				
Operating and administrative			533	481
Finance expense		4	489	423
Depreciation and amortization			423	381
Water rentals and assessments		5	118	119
Fuel and power purchased			133	146
Capital and other taxes			105	103
			1 801	1 653
Net income before non-controlling interest			79	61
Net loss attributable to non-controlling interest		22	13	-
Net Income			92	61

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2013	2012
	millions of dollars	
Retained earnings, beginning of year	2 450	2 389
Net income	92	61
Retained earnings, end of year	2 542	2 450

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEET

As at March 31

	Notes	2013	2012
		millions of dollars	
Assets			
Property, Plant and Equipment			
In service	6	15 793	13 631
Less accumulated depreciation	6	5 252	4 984
		10 541	8 647
Construction in progress	6	1 967	3 150
		12 508	11 797
Current Assets			
Cash and cash equivalents		32	50
Accounts receivable and accrued revenue		421	328
Interest receivable		4	4
Materials and supplies, at average cost	7	93	106
		550	488
Other Assets			
Sinking fund investments	8	352	372
Goodwill and intangible assets	9	276	268
Regulated assets	10	306	310
Other long-term assets	11	550	556
		1 484	1 506
		14 542	13 791

Approved on behalf of the Board:

William C. Fraser, FCA
Chair of the Board

James Husiak, CA
Chair of the Audit Committee

	Notes	2013	2012
		millions of dollars	
Liabilities and Equity			
Long-Term Debt			
Long-term debt net of sinking fund investments		8 977	8 729
Sinking fund investments shown as assets	8	352	372
	12	9 329	9 101
Current Liabilities			
Accounts payable and accrued liabilities	13	421	361
Accrued interest		103	104
Current portion of long-term debt	12	656	281
		1 180	746
Other Liabilities			
Asset purchase obligation	14	207	207
Other long-term liabilities	15	550	542
		757	749
Contributions in Aid of Construction		340	318
Equity			
Retained earnings		2 542	2 450
Accumulated other comprehensive income		299	327
		2 841	2 777
Non-controlling interest	22	95	100
		2 936	2 877
		14 542	13 791

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended March 31

	2013	2012
	millions of dollars	
Operating Activities		
Cash receipts from customers	2 015	2 008
Cash paid to suppliers and employees	(981)	(1 058)
Interest paid	(489)	(418)
Interest received	44	35
Cash provided by operating activities	589	567
Financing Activities		
Proceeds from long-term debt	807	698
Sinking fund withdrawals	129	23
Retirement of long-term debt	(242)	(25)
Other	(59)	29
Cash provided by financing activities	635	725
Investing Activities		
Property, plant and equipment, net of contributions	(1 037)	(1 124)
Sinking fund payments and deposits	(107)	(98)
Other	(98)	(90)
Cash used for investing activities	(1 242)	(1 312)
Net decrease in cash and cash equivalents	(18)	(20)
Cash and cash equivalents, beginning of year	50	70
Cash and cash equivalents, end of year	32	50

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year ended March 31

	2013	2012
	millions of dollars	
Net Income	92	61
Other Comprehensive Loss		
Unrealized foreign exchange losses on debt in cash flow hedges	(31)	(54)
Realized foreign exchange losses on debt in cash flow hedges reclassified to income	2	-
Unrealized fair value gains on available-for-sale U.S. sinking fund investments	1	14
	(28)	(40)
Comprehensive Income	64	21

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME

For the year ended March 31

	2013	2012
	millions of dollars	
Balance, beginning of year	327	367
Other comprehensive loss	(28)	(40)
Balance, end of year	299	327

The accompanying notes are an integral part of the consolidated financial statements.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

NOTE 1 SIGNIFICANT ACCOUNTING POLICIES

Nature of the Organization - The Manitoba Hydro-Electric Board and the Manitoba Power Commission were amalgamated in 1961 by enactment of *The Manitoba Hydro Act* to form a Crown Corporation in the Province of Manitoba named Manitoba Hydro (the Corporation). Manitoba Hydro's mandate is to provide for the continuance of a supply of energy adequate for the needs of the province and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of energy. The head office of the Corporation is located at 360 Portage Avenue, Winnipeg, Manitoba.

Basis of Presentation - These consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Canadian Institute of Chartered Accountants (CICA) Accounting Handbook - Pre-Changeover Accounting Standards and include the significant accounting policies described hereafter.

Consolidation - These consolidated financial statements include the accounts of Manitoba Hydro and its wholly-owned subsidiaries including Centra Gas Manitoba Inc. (Centra), Minell Pipelines Ltd., Manitoba Hydro International Ltd. (MHI), Manitoba Hydro Utility Services Ltd. (MHUS) and Teshmont LP Holdings Ltd. (which has a 40% ownership interest in the Teshmont Consultants Limited Partnership). These consolidated financial statements also include Manitoba Hydro's 67% ownership interest in the Wuskwatim Power Limited Partnership (WPLP) and its 75% ownership in the Keeyask Hydropower Limited Partnership. For purposes of consolidation, all significant intercompany accounts and transactions have been eliminated.

Rate-Regulated Accounting - The prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the Public Utilities Board of Manitoba (PUB). The rate-setting process is designed such that rates charged to electricity and natural gas customers recover costs incurred by Manitoba Hydro in providing electricity and gas service. As permitted under Canadian GAAP, the Corporation applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of Canadian GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Manitoba Hydro applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise have been included in the determination of net income in the year that the cost or credit is incurred. Manitoba Hydro refers to such deferred costs or credits as regulated assets (Note 10) or regulated liabilities (Note 13) which are generally comprised of the following:

- Power Smart programs - The costs of the Corporation's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.

- Site restoration costs - Site restoration costs, other than those for which an asset retirement obligation has been established, are deferred and amortized on a straight-line basis over a period of 15 years.

- Deferred taxes - Taxes paid by Centra (July 1999) as a result of its change to non-taxable status on acquisition by Manitoba Hydro, have been deferred and are being amortized on a straight-line basis over a period of 30 years.

- Acquisition costs - Costs associated with the acquisition of Centra (July 1999) and Winnipeg Hydro (September 2002) have been deferred and are being amortized on a straight-line basis over a period of 30 years.

- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. The difference between the recorded cost of natural gas and the actual cost of natural gas is carried as an account receivable/payable and recovered or refunded in future rates.

- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.

Manitoba Hydro's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Property, plant and equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases and depreciation and interest charged to operations commences.

b) **Depreciation**
Depreciation is provided on a straight-line remaining-life basis. The major components of generating stations are depreciated over the lesser of the remaining life of the major component or the remaining life of the associated generating station.

The range of estimated service lives of each major asset category is as follows:

Generation	- Hydraulic	20 - 125 years
	- Thermal	5 - 65 years
Transmission lines		10 - 85 years
Substations		15 - 65 years
Distribution		10 - 75 years
Other		5 - 100 years

Provision for removal costs of major property, plant and equipment is charged to depreciation expense on a straight-line basis over the remaining service lives of the related assets. Retirements of these assets, including costs of removal, are charged to accumulated depreciation with no gains or losses reflected in operations. The estimated service lives and removal costs of the assets are based upon depreciation studies conducted periodically by the Corporation.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

c) **Asset Retirement Obligations**
Asset retirement obligations are measured initially at fair value in the period in which the obligations are incurred, provided that a reasonable estimate of the fair value can be made. The present value of the estimated retirement cost is added to the carrying amount of the related asset. In subsequent periods, the estimated retirement cost is amortized over the useful life of the asset and the carrying value of the liability is increased to recognize increases in the liability's present value with the passage of time.

d) **Materials and Supplies**
Materials and supplies are valued at the lower of average cost or net realizable value.

e) **Contributions in Aid of Construction**
Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

f) **Revenues**
Customers' meters are read and billed on a cyclical basis. Revenues are accrued in respect of energy delivered for those cycles not yet billed.

g) **Cost of Gas Sold**
Cost of natural gas sold is recorded at the same rates charged to customers.

h) **Employee Future Benefits**
Manitoba Hydro provides future benefits, including pension and other post-retirement benefits, to both existing and retired employees. Pension plans include the Civil Service Superannuation Board (CSSB) plan, the Enhanced Hydro Benefit Plan (EHBP), three Centra curtailed pension plans and the Winnipeg Civic Employee Benefits Program (WCEBP). MHUS is a matching employer under the Civil Service Superannuation Act and MHI sponsors a defined contribution group registered retirement plan.

The costs and obligations of pension and other post-retirement benefits are calculated by an independent actuary using the accrued benefit actuarial cost method and reflect management's best estimate of future compensation increases, service lives, inflation rates and expected rate of return on plan assets. Pension expense is comprised of the cost of pension benefits provided during the year, the amortization of past service benefits, experience gains and losses and expected returns on fund assets net of interest on the obligation. The amount of expected returns on fund assets is based on market related values using a five-year moving average. The unamortized present value of past service benefits and actuarially determined experience gains or losses are recognized in the consolidated financial statements as assets or liabilities.

The Corporation utilizes the "corridor method" of amortizing actuarial gains and losses. The amortization of experience gains and losses is recognized only to the extent that the cumulative unamortized net actuarial gain or loss exceeds 10% of the greater of the accrued benefit obligation and the fair market value of plan assets at the beginning of the year. When required, the excess of the cumulative gain or loss balance is amortized over the expected average remaining service life of the employees covered by the plan.

Pension and long-term disability expenses pertaining to the former Winnipeg Hydro employees are recognized at the time contributions are made to the WCEBP, which maintains the funds and obligations relating to these employees in its financial records.

Other employee benefits earned by employees include vacation, vested sick leave, severance and a retirement health spending plan. Where applicable, the future costs of these benefits are based on management's best estimates.

i) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). OCI includes unrealized gains and losses arising from changes in the fair value of available-for-sale assets and changes in the foreign exchange rate for U.S. denominated long-term debt and interest payments in effective cash flow hedging relationships. Such amounts are recorded in accumulated OCI (AOCI) until the criteria for recognition in net income are met.

j) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Transaction costs are included in the initial carrying amount of financial instruments. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale or other financial liabilities.

Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are measured at fair value with revaluation gains and losses recorded in OCI until the instrument is derecognized or impaired. Translation gains and losses on available-for-sale financial assets in a hedging relationship with financial liabilities are credited or charged to finance expense. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in income in the period in which they arise.

k) **Foreign Currency Translation**
Revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollar equivalents at exchange rates in effect at the transaction dates.

Long-term monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date. Translation gains and losses are credited or charged to finance expense in the current period except for long-term debt obligations in hedging relationships with future export revenues. Translation gains and losses for long-term debt obligations in hedging relationships with future export revenues are recorded in OCI until such time that the hedged export revenues are realized, at which time accumulated exchange gains and losses are credited or charged to finance expense.

Current monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date. Any exchange gains and losses on the translation of current monetary assets and liabilities are credited or charged to finance expense in the current period.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

l) **Derivatives**
The Corporation does not engage in derivative trading or speculative activities. All derivative instruments are carried at fair value on the consolidated balance sheet with the exception of those that were entered into for the purpose of physical receipt or delivery in accordance with the Corporation's expected normal purchases and sales. Changes in the fair value of derivatives that are not designated in a hedging relationship and do not qualify for the normal purchase and sale exemption are recorded in net income.

m) **Hedges**
The Corporation has designated cash flow and fair value hedges linking financial instruments to specific assets and forecasted transactions. Long-term cash flow hedges have been established between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. A fair value hedge relationship has also been established between U.S. long-term debt balances and U.S. sinking fund investments. The Corporation documents the relationship between the hedging instrument and the hedged item and assesses at inception, and on an ongoing basis, the effectiveness of the hedging relationship.

n) **Debt Discounts and Premiums**
Debt discounts and premiums are amortized to finance expense using the effective interest method.

o) **Cash and Cash Equivalents**
Cash and cash equivalents include cash on hand and short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

p) **Goodwill and Intangible Assets**
Goodwill represents the amount of the Corporation's investments in Centra and Winnipeg Hydro over and above the fair market value of the identified net assets acquired. The goodwill balance is evaluated annually to determine whether any impairment has occurred. An impairment would be recognized if it was determined that the carrying value of the Corporation's investments in Centra or Winnipeg Hydro exceeded the present value of the future cash flows from these investments. Should impairment occur, it would be recorded as a charge against operations in the year of impairment.

Intangible assets include computer software, application development costs, land easements and transmission rights. Intangible assets are recorded at cost. The cost of computer software and application development includes software, direct labour, materials, contracted services, a proportionate share of overhead costs and interest during development applied at the average cost of debt. Intangible assets with finite useful lives are amortized over their useful lives on a straight-line basis. The expected useful lives are as follows:

Computer software and application development	5 – 10 years
Land easements	75 years

The estimated service lives of intangible assets are based upon depreciation studies conducted periodically by the Corporation. The transmission rights are amortized over the contractual period plus a one-term renewal.

q) **Non-Controlling Interest**
Non-controlling interest represents the outstanding ownership interests attributable to third parties in the Corporation's limited partnerships. The portion of the property, plant and equipment not owned by the Corporation is reflected as non-controlling interest within the equity section of the consolidated balance sheet. The portion of the net income or net loss not attributed to the Corporation is recorded as a non-controlling interest in the consolidated statement of income.

r) **Use of Estimates**
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Actual amounts could differ from those estimates, but differences are not expected to be material.

NOTE 2 ACCOUNTING CHANGES

Overhead Rate Estimate
Manitoba Hydro's policy is to include a proportionate share of overhead costs in property, plant and equipment based on overhead rate studies that are performed annually. In 2012, the Corporation revised its overhead rate estimate to remove information technology infrastructure and related support costs and common building depreciation and operating costs. This change in estimate was applied prospectively effective April 1, 2012 and resulted in a $32 million increase in operating and administrative expense in 2012-13.

Future Accounting Changes

International Financial Reporting Standards (IFRS)
In February 2008, the Canadian Accounting Standards Board (AcSB) announced that publicly accountable enterprises would be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. In October 2009, the Public Sector Accounting Board confirmed that government business enterprises such as Manitoba Hydro would be required to follow IFRS for periods beginning January 1, 2011.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. The areas with the highest potential to impact Manitoba Hydro include property, plant and equipment, regulatory assets and liabilities, employee benefits and the transitional requirements upon the adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS.

In May 2010, the International Accounting Standards Board (IASB) issued the omnibus Improvements to IFRS, which includes an amendment to IFRS 1 for entities with rate-regulated activities. The amendment applies to first-time adopters by offering an optional exemption to use the carrying amount of property, plant and equipment and intangible assets as deemed cost of those assets on the transition date. This exemption eliminates the requirement to retrospectively adjust opening property, plant and equipment and/or intangible asset balances for costs that would otherwise not qualify for capitalization under IFRS. Manitoba Hydro intends to apply this exemption.

Notes to the Consolidated Financial Statements
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In September 2010, the AcSB implemented changes to Part I of the CICA Handbook – International Financial Reporting Standards, allowing qualifying entities with rate-regulated activities to be permitted, but not required, to defer their adoption of IFRS for one year. In March 2012, September 2012 and February 2013, the AcSB announced additional optional one-year deferrals of IFRS for qualifying entities with rate-regulated activities. Manitoba Hydro meets the AcSB criteria for deferral and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On April 25, 2013, the IASB issued the Exposure Draft - Regulatory Deferral Accounts. The Exposure Draft proposes an interim standard intended to allow entities that are first-time adopters of IFRS and that currently recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) in accordance with their existing GAAP, to continue to do so upon transition. Under the proposed interim standard, entities will be able to avoid making major changes in accounting for regulatory assets and liabilities on transition to IFRS until the IASB can provide more guidance through its Rate-regulated Activities project. Comments on the Exposure Draft are due in September of 2013 and the IASB is not expected to make a decision on the proposed interim standard until December of 2013.

At this time, it is uncertain as to the final position the IASB will take as part of its Rate-regulated Activities project. In addition, the IASB has a number of on-going projects on its agenda which may result in modifications to existing IFRS prior to the commencement of Manitoba Hydro's 2015-16 fiscal year. Manitoba Hydro continues to monitor and evaluate the impacts of current and prospective IFRS on its accounting policies, financial position and business activities.

NOTE 3 EXTRAPROVINCIAL REVENUES

	2013	2012
	millions of dollars	
United States	312	315
Canada	41	48
	353	363

U.S. extraprovincial revenues were translated into Canadian dollars at exchange rates in effect at the date of the transaction. The average effective exchange rate for the year was $1.00 U.S. = $1.00 Canadian (2012 - $1.00 U.S. = $0.98 Canadian).

NOTE 4 FINANCE EXPENSE

	2013	2012
	millions of dollars	
Interest on debt	636	603
Interest capitalized	(141)	(170)
Investment income	(11)	(13)
Realized foreign exchange losses on debt in cash flow hedges	2	-
Realized losses on revaluation of dual currency bonds	3	3
	489	423

Included in interest on debt is $93 million (2012 - $85 million) related to the Provincial Debt Guarantee Fee. The fee during the year was 1.0% of the total outstanding debt guaranteed by the Province of Manitoba (2012 - 1.0%).

NOTE 5 WATER RENTALS AND ASSESSMENTS

	2013	2012
	millions of dollars	
Water rentals	111	111
Assessments	7	8
	118	119

Water rentals are paid to the Province of Manitoba for the use of water resources in the operation of the Corporation's hydroelectric generating stations. Water rental rates during the year were $3.34 per MWh (2012 - $3.34 per MWh).

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

	2013			2012		
	In service	Accumulated depreciation	Construction in progress	In service	Accumulated depreciation	Construction in progress
			millions of dollars			
Generation						
Hydraulic	6 645	1 739	1 222	5 188	1 658	2 276
Thermal	480	277	11	475	260	11
Transmission lines	1 024	311	127	855	296	246
Substations	2 977	1 337	489	2 668	1 260	489
Distribution	3 471	1 242	95	3 268	1 193	105
Other	1 196	346	23	1 177	317	23
	15 793	5 252	1 967	13 631	4 984	3 150

During fiscal 2012-13 the 3 units of the Wuskwatim Generating Station and the associated transmission facilities were transferred from construction in progress and placed in-service. The in-service amounts are as follows: generating station - $1 356 million, transmission line - $153 million, substation and other - $174 million.

NOTE 7 MATERIALS AND SUPPLIES

	2013	2012
	millions of dollars	
Materials and supplies	72	65
Natural gas inventory	21	41
	93	106

NOTE 8 SINKING FUND INVESTMENTS

Manitoba Hydro is legislated under *The Manitoba Hydro Act* to make annual sinking fund payments to the Province of Manitoba of not less than 1% of the principal amount of the outstanding debt on the preceding March 31, and 4% of the balance in the sinking fund at such date. Payments to the sinking fund during the year were $107 million (2012 - $98 million). Income earned on sinking fund investments is included with investment income for the year.

Sinking funds are invested in government bonds and the bonds of highly rated corporations and financial institutions.

	2013	2012
	millions of dollars	
Canadian investments	58	129
U.S. investments	272	217
Premium on purchase of sinking fund investments	22	26
	352	372

Canadian investments have a weighted average term to maturity of 1 day (2012 - 1 day) and an effective yield to maturity of 1.1% (2012 - 1.0%). U.S. investments have a weighted average term to maturity of 4.0 years (2012 - 6.0 years) and an effective yield to maturity of 3.7% (2012 – 4.8%). U.S. investments are translated into Canadian dollars at the exchange rate prevailing at the consolidated balance sheet date, $1.00 U.S. = $1.02 Canadian (2012 - $1.00 U.S. = $1.00 Canadian). The March 31, 2013 balance includes $29 million (2012 - $28 million) of unrealized fair value gains.

NOTE 9 GOODWILL AND INTANGIBLE ASSETS

	2013			2012		
	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
			millions of dollars			
Intangible Assets						
Computer software and application development	210	105	105	201	93	108
Land easements	72	13	59	64	12	52
Transmission rights	5	1	4	-	-	-
	287	119	168	265	105	160
Goodwill	108	-	108	108	-	108
	395	119	276	373	105	268

The additions to intangible assets for the year totaled $31 million (2012 - $27 million). In total, intangible assets of $23 million (2012 - $20 million) were amortized to operations during the period.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

NOTE 10 REGULATED ASSETS

		2013	2012
		millions of dollars	
Power Smart programs	- electric	172	174
	- gas	47	44
Site restoration costs		35	36
Deferred taxes		29	31
Acquisition costs		20	21
Regulatory costs		3	4
		306	310

If the Corporation was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and net income for 2013 would have been increased by $4 million (2012 – decreased by $1 million).

In total, regulated assets of $46 million (2012 - $43 million) were amortized to operations during the period.

NOTE 11 OTHER LONG-TERM ASSETS

	2013	2012
	millions of dollars	
Advances to St. Joseph Windfarm Inc. (excluding current portion)	227	235
Accrued benefit asset (Note 18)	122	127
Advances to Taskinigahp Power Corporation (Note 22)	105	100
Contract receivables	81	74
Affordable Energy Fund (Note 21)	15	20
	550	556

The St. Joseph wind farm is owned by Pattern Energy and operated by St. Joseph Windfarm Inc. Financing for the wind farm was provided partly by Manitoba Hydro. In accordance with the loan agreement, Manitoba Hydro provided advances of $250 million, which will be repaid with interest over 20 years. In addition, Manitoba Hydro has provided access to a $10 million reserve loan facility. The Corporation signed a 27-year power purchase agreement with St. Joseph Windfarm Inc. in March 2010.

NOTE 12 LONG-TERM DEBT

	2013	2012
	millions of dollars	
Advances from the Province of Manitoba represented by debenture debt of the Province	9 775	9 095
Manitoba HydroBonds	55	136
Manitoba Hydro-Electric Board Bonds	182	194
	10 012	9 425
Less: Current portion of long-term debt	656	281
	9 356	9 144
Adjustment to carrying value of dual currency bonds	(20)	(24)
Debt discounts and premiums	22	9
Transaction costs	(29)	(28)
	9 329	9 101

During the year, the Corporation arranged long-term financing of $807 million (2012 - $698 million). The current year financing was in the form of Provincial Advances with the majority at fixed interest rates.

Included in the current portion of long-term debt are $617 million (2012 - $177 million) of debt maturities and $39 million (2012 - $104 million) of floating-rate Manitoba HydroBonds with maturity dates in 2017. Floating rate Manitoba HydroBonds are redeemable at the option of the holder.

Long-term debt is guaranteed by the Province of Manitoba, with the exception of Manitoba Hydro-Electric Board Bonds in the amount of $73 million (2012 - $74 million) issued for mitigation projects.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

Debt principal amounts (excluding adjustments to the carrying value of dual currency bonds, transaction costs, debt discounts and premiums) and related yields are summarized by fiscal years of maturity in the following table:

					2013	2012
		millions of Canadian dollars				
Years of Maturity	Canadian	Cdn. Yields	U.S.	U.S. Yields	Total	Total
2014	312	3.3%	344	4.8%	656	812
2015	109	1.8%	101	2.9%	210	209
2016	313	4.6%	-	-	313	313
2017	308	3.6%	-	-	308	308
2018	331	6.9%	-	-	331	531
	1 373	5.0%	445	4.1%	1 818	2 173
2019-2023	1 737	4.6%	1 625	6.6%	3 362	2 540
2024-2028	450	6.2%	-	-	450	450
2029-2033	1 050	8.7%	-	-	1 050	1 049
2034-2038	1 025	5.0%	-	-	1 025	1 025
2039-2043	1 700	4.5%	-	-	1 700	1 400
2044-2063	607	4.3%	-	-	607	507
	7 942	5.2%	2 070	6.6%	10 012	9 144

Included in the above Canadian maturity amounts are two dual currency bonds with principal amounts repayable in Canadian currency and interest payments denominated in U.S. currency. The first dual currency bond matures in the 2013-14 fiscal year in the amount of $208 million Canadian while the second matures in the 2025-26 fiscal year in the amount of $130 million Canadian.

U.S. debt is translated into Canadian dollars at the exchange rate prevailing at the balance sheet date, $1.00 U.S. = $1.02 Canadian (2012 - $1.00 U.S. = $1.00 Canadian).

NOTE 13 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2013	2012
	millions of dollars	
Accounts payable and accrued liabilities	397	308
Regulated liabilities		
Purchased gas variance accounts	24	30
Rate reduction	-	23
	421	361

The Corporation passes all costs related to the purchase and transportation of natural gas on to its customers without markup. If the Corporation were not subject to rate regulation, the purchased gas variance accounts would not be maintained and the actual cost of gas would be expensed in the period incurred. If actual gas costs were expensed and sales rates were not adjusted accordingly, net income would have decreased by $6 million (2012 - increased by $17 million).

In Order 5/12 dated January 17, 2012, the PUB had directed that the 2.9% electricity rate increase previously approved on an interim basis effective April 1, 2010 be reduced to 1.9% and that the associated revenues were to be set aside as a regulatory deferral until further direction was provided by the PUB. The cumulative impact of the 1.0% rate reduction for the 2010-11 and 2011-12 fiscal years was recorded as a reduction to revenues of $23 million in 2011-12 and reflected as a regulatory deferral. In Order 43/13 dated April 26, 2013, the PUB approved the Corporation’s application to reinstate the 1.0% rate deferral as revenue in the 2012-13 fiscal year and as a result the balance in the deferral account as at March 31, 2013 is nil.

NOTE 14 ASSET PURCHASE OBLIGATION

Effective September 3, 2002, the Corporation acquired the net assets of Winnipeg Hydro from the City of Winnipeg. The asset purchase obligation represents the net present value of payments to the City of Winnipeg of $16 million per annum in perpetuity.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

NOTE 15 OTHER LONG-TERM LIABILITIES

	2013	2012
	millions of dollars	
Mitigation liability (Note 20)	235	251
Accrued benefit liability (Note 18)	174	156
Refundable advances from customers	96	87
Affordable Energy Fund (Note 21)	15	20
Transmission development fund	15	16
Asset retirement obligations	9	9
Other	6	3
	550	542

The Corporation recorded a liability for the transmission development fund for both the Wuskwatim transmission line and the Herblet Lake transmission line as outlined in the Wuskwatim Project Development Agreement. These funds will be used for community development purposes by eligible First Nations and small or remote northern communities in the vicinity of the transmission lines.

Asset retirement obligations continue to be recognized for the future decommissioning of the Brandon thermal generating station and for the partial decommissioning of the Pointe du Bois generating station spillway. The Corporation estimates the undiscounted cash flows required to settle the asset retirement obligations are approximately $17 million (2012 - $19 million), $15 million (2012 - $15 million) of which is expected to be incurred in 2024 to decommission the Brandon thermal generating station and $2 million (2012 - $4 million) is expected to be incurred by March 2015 for the partial decommissioning of the Pointe du Bois generating station spillway. No funds are being set aside to settle the asset retirement obligations.

NOTE 16 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of the Corporation's non-derivative financial instruments at March 31 were as follows:

	2013		2012	
Financial Instruments	Carrying value	Fair value	Carrying value	Fair value
	millions of dollars			
Held-for-trading				
Cash and cash equivalents	32	32	50	50
Loans and receivables				
Accounts receivable and accrued revenue	421	421	328	328
Interest receivable	4	4	4	4
Available-for-sale				
Sinking fund investments	352	352	372	372
Other financial liabilities				
Long-term debt (including current portion)	9 985	12 335	9 382	11 712
Accounts payable and accrued liabilities	421	421	361	361
Accrued interest	103	103	104	104
Asset purchase obligation	207	343	207	340

The fair value measurement of financial instruments is classified in accordance with a hierarchy of three levels, based on the type of inputs used in making these measurements:

Level 1 - Quoted prices in active markets for identical assets and liabilities;
Level 2 - Inputs other than quoted prices that are observable in active markets for the asset or liability; and
Level 3 - Inputs for the asset or liability that are not based on observable market data.

Financial instrument measurements are Level 1 measurements with the exception of the long-term debt and the asset purchase obligation that are Level 2 measurements and certain derivative instruments of nominal value associated with wholesale power marketing activities that are Level 3 measurements. Fair value Level 2 measurements are derived from quoted market yields at the close of business on the consolidated balance sheet date for similar instruments available in the capital market. Level 3 measurements are based on internally developed valuation models which are consistent with valuation models developed by other market participants in the wholesale power markets. The carrying values of all other financial assets and liabilities approximate their fair values.

Notes to the Consolidated Financial Statements
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Financial Risks

During the normal course of business, Manitoba Hydro is exposed to a number of financial risks including credit and liquidity risks and market risk resulting from fluctuations in foreign currency, interest rates and commodity prices. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by the Corporation and its subsidiaries, to set risk tolerance limits, establish controls and to monitor risk and adherence to policies. An integrated risk management plan has been developed and reviewed by the Manitoba Hydro-Electric Board to ensure the adequacy of the risk management framework in relation to the risks faced by the Corporation. The nature of the financial risks and Manitoba Hydro's strategy for managing these risks has not changed significantly from the prior year.

a) Credit Risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Manitoba Hydro is exposed to credit risk related to sinking fund investments, short-term investments and pension fund investments. The Corporation limits its exposure to credit risk by only investing in government-guaranteed bonds, highly rated investments and well-diversified investment portfolios.

The Corporation is also exposed to credit risk related to domestic and export energy sales. Credit risk related to domestic sales is mitigated by the large and diversified electric and gas customer base. Credit risk in the export power market is mitigated by establishing credit requirements, conducting standard credit reviews of all counterparties and setting and monitoring exposure limits for each of these counterparties. Letters of credit and netting provisions are also in place to further mitigate credit risk. The maximum exposure to credit risk related to domestic and export energy sales is its fair value.

The value of the Corporation's aged accounts receivable and related bad debt provisions are presented in the following table:

	Manitoba	Extraprovincial	2013 Total	2012 Total
		millions of dollars		
Under 30 days	315	27	342	260
31 to 60 days	25	-	25	14
61 to 90 days	8	-	8	9
Over 90 days	26	-	26	28
	374	27	401	311
Provision at end of period	(9)	-	(9)	(8)
Total accounts receivable	365	27	392	303

The provision for bad and doubtful accounts is reviewed annually, based on an estimate of aged receivables that are considered uncollectible.

To mitigate credit risk related to the use of natural gas derivative instruments, the Corporation adheres to well established credit exposure limits with institutions that possess a minimum credit rating of 'A' from recognized bond rating agencies or provide a parental guarantee from an 'A' rated parent company. The Corporation's maximum exposure to credit risk related to its derivative counterparties is equal to the positive fair value of its financial derivatives.

b) Liquidity Risk

Liquidity risk refers to the risk that Manitoba Hydro will not be able to meet its financial obligations as they come due. The Corporation meets its financial obligations when due through cash generated from operations, short-term borrowings, long-term borrowings advanced from the Province of Manitoba and sinking fund withdrawals.

The following is an analysis of the contractual undiscounted cash flows payable under financial liabilities and derivative liabilities as at the balance sheet date:

	Carrying value	2014	2015	2016	2017	2018	2019 and thereafter
				millions of dollars			
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	421	421	-	-	-	-	-
Asset purchase obligation	207	16	16	16	16	16	16*
Long-term debt**	10 088	1 293	822	932	916	908	14 719
		1 730	838	948	932	924	14 719
Derivative financial liabilities							
Commodity derivatives							
Fixed price swap contracts	-	-	-	-	-	-	-
		-	-	-	-	-	-
		1 730	838	948	932	924	14 719

*per year in perpetuity
**including current portion and interest payments

c) Market Risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Manitoba Hydro is exposed to three types of market risk: foreign exchange risk, interest rate risk and commodity price risk associated with the price of electricity and natural gas. Manitoba Hydro continually monitors its exposure to these risks and may use hedges or derivative contracts to manage these risks.

i. Foreign Exchange Risk

Manitoba Hydro has exposure to U.S. dollar foreign exchange rate fluctuations primarily through the sale and purchase of electricity in the U.S. and through borrowing in U.S. markets. This exposure is managed through a long-term natural hedge between U.S. dollar cash inflows from export revenues and U.S. dollar cash outflows for long-term coupon and principal payments.

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To mitigate annual net income impacts due to foreign exchange rate fluctuations, long-term cash flow hedges have been established between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. Accordingly, translation gains and losses for U.S. long-term debt obligations in effective hedging relationships with future export revenues, are recognized in other comprehensive income until future hedged U.S. export revenues are realized, at which time the associated gains or losses in accumulated other comprehensive income are recognized in net income. For the year ended March 31, 2013, unrealized foreign exchange translation losses of $31 million (2012 - $54 million losses) were recognized in other comprehensive income and $2 million net losses (2012 - nil) were reclassified from other comprehensive income into net income.

Manitoba Hydro also has a fair value hedging relationship between U.S. long-term debt balances and U.S. sinking fund investments. Offsetting foreign exchange translation gains and losses on these items are recognized in net income.

In addition to natural hedging relationships, cross currency swap arrangements transacted by the Province of Manitoba on the Corporation's behalf are utilized to manage exchange rate exposures and as a means to capitalize on favourable financing terms in either U.S. or Canadian capital markets. Cross currency agreements represent an exchange of principal and/or interest flows denominated in one currency for principal and/or interest flows denominated in another. Such transactions effectively amend the terms of the original debt obligation with the Province of Manitoba with the swapped debt arrangement.

As at March 31, 2013, a change in the Canadian dollar of plus (minus) $0.10 relative to the U.S. dollar would decrease (increase) net income by $0.4 million (2012 - $0.2 million), while other comprehensive income would increase (decrease) by $177 million (2012 - $182 million).

ii. Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. Manitoba Hydro is exposed to interest rate risk associated with temporary investments, floating rate long-term debt and fixed rate long-term debt maturing within 12 months, less sinking fund withdrawals, offset by the change in interest capitalization. As at March 31, 2013, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $15 million (2012 - $10 million), with no impact to other comprehensive income.

Interest rate swap agreements transacted by the Province of Manitoba on the Corporation's behalf are utilized to manage the fixed and floating interest rate mix of the total debt portfolio, interest rate exposure and related overall cost of borrowing. Interest rate swap agreements represent an agreement between two parties to periodically exchange payments of interest without the exchange of the principal amount upon which payments are based. The Province of Manitoba may also enter into forward start interest rate swap arrangements where the agreement to exchange interest payments commences at some future date. In either swap arrangement, the terms of the debt advanced by the Province of Manitoba to the Corporation are amended by the swap.

iii. Commodity Price Risk
The Corporation is exposed to electricity price risk that results from volatility of market prices and natural gas price risk through its purchase of gas for delivery to customers throughout Manitoba. The Corporation mitigates commodity price risk through its limited use of derivative financial instruments restricted to contracts for differences and natural gas price swaps. Manitoba Hydro does not use derivative contracts for trading or speculative purposes.

The Corporation has entered into natural gas price swaps until July 2016 to purchase 231 510 gigajoules of natural gas at a weighted average fixed price of $5.12/GJ. The weighted average forward price of the swaps per AECO at March 31, 2013 was $3.67/GJ. These contracts are reported as derivatives and carried at fair value on the balance sheet.

The unrealized fair value gains (losses) of financial derivative contracts as at March 31 are as follows:

	2013	2012
	millions of dollars	
Fixed price swap contracts	-	(1)
Contracts for differences	-	1

Fair values of price swaps are calculated using the monthly forward AECO price as reported by the Natural Gas Exchange as at March 31, 2013.

Fair values of contracts for differences are calculated using the monthly forward electricity prices at pricing points specified in the contracts.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

NOTE 17 CAPITAL MANAGEMENT

Manitoba Hydro manages its capital structure to ensure that there is sufficient equity to absorb the financial effects of adverse circumstances and to ensure continued access to stable low-cost funding for capital projects and ongoing operational requirements.

The Corporation monitors its capital structure on the basis of its equity ratio. Manitoba Hydro's current target is to maintain a minimum equity ratio of 25%.

The Corporation's equity ratio as at March 31 was as follows:

	2013	2012
	dollars are in millions	
Long-term debt, net of sinking fund investments	8 977	8 729
Current portion, long-term debt	656	281
Less: Cash and cash equivalents	(32)	(50)
Net debt	9 601	8 960
Retained earnings	2 542	2 450
Accumulated other comprehensive income	299	327
Contributions in aid of construction	340	318
Non-controlling interest	95	100
Total equity	3 276	3 195
Equity ratio	25%	26%

Manitoba Hydro issues debt for its capital requirements under the authority of *The Manitoba Hydro Act* and *The Loan Act*. *The Manitoba Hydro Act* grants the Corporation the power to issue up to $500 million of short-term promissory notes. Manitoba Hydro submits annual requests under *The Loan Act* for the necessary borrowing authority for new capital requirements and the refinancing of any maturing long-term debt. The majority of Manitoba Hydro's long-term debt is obtained through advances by the Province of Manitoba.

NOTE 18 EMPLOYEE FUTURE BENEFITS

Manitoba Hydro employees are eligible for pension benefits under the CSSB defined benefit plan that provides pension benefits based on years of service and on the average earnings of the five best years. The CSSB plan requires the Corporation to contribute approximately 50% of the pension disbursements made to retired employees. All current employees participating in the CSSB plan are eligible for enhanced pension benefits under the EHBP. The EHBP improves the pension formula used to calculate pension for active service accrued after June 1, 2006. In addition, the former employees of Centra are entitled to pension benefits earned under the Centra curtailed pension plans. The former Winnipeg Hydro employees continue to earn benefits under the WCEBP in which, upon the acquisition of Winnipeg Hydro, Manitoba Hydro became a participating employer. The WCEBP is also a defined benefit plan that provides pension benefits based on years of service and on the average earnings of the five best years.

The CSSB manages the Corporation's pension funds (MH Pension Fund and EHBP) on behalf of the Corporation. The assets related to the Centra curtailed pension plans are held in trust by State Street Trust Co. of Canada. The assets and liabilities of the WCEBP are not reflected on Manitoba Hydro's consolidated balance sheet.

MHUS employees are eligible for pension benefits under the CSSB defined benefit plan. As a matching employer under the Civil Service Superannuation Act, MHUS is required to match employee contributions at a prescribed rate into the Civil Service Superannuation Fund pool of assets. MHUS' pension expense is recognized at the time contributions are made to the fund. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements related to the MHUS defined benefit plan.

MHI sponsors a defined contribution group registered retirement plan. MHI matches 100% of the employee contributions at prescribed contribution rates. The cost of the pension benefits is charged to pension expense as services are rendered. Manitoba Hydro does not carry a pension asset or obligation on its consolidated financial statements for the MHI defined contribution plan.

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

The following table presents information pertaining to the MH Pension Fund, the EHBP and the Centra curtailed pension plans:

	MH Pension Fund		Enhanced Hydro Benefit Plan		Centra curtailed pension plans		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
	millions of dollars							
Plan assets at fair value								
Balance at beginning of year	758	763	11	-	84	84	853	847
Actual return on plan assets	52	14	1	-	6	2	59	16
Employer contributions	26	23	2	11	12	2	40	36
Benefit payments and refunds	(44)	(42)	-	-	(5)	(4)	(49)	(46)
	792	758	14	11	97	84	903	853
Accrued benefit obligation								
Balance at beginning of year	1 012	837	11	-	98	86	1 121	923
Transfer in - other benefits	-	-	-	9	-	-	-	9
Interest on obligation	53	54	1	-	5	6	59	60
Current service cost	35	27	2	2	-	-	37	29
Benefit payments and refunds	(45)	(43)	-	-	(5)	(4)	(50)	(47)
Actuarial losses	177	137	6	-	15	10	198	147
	1 232	1 012	20	11	113	98	1 365	1 121
Deficit at end of year	(440)	(254)	(6)	-	(16)	(14)	(462)	(268)
Unamortized past service costs	-	-	-	-	1	2	1	2
Unamortized transitional balance	(1)	(2)	-	-	-	-	(1)	(2)
Unamortized net actuarial loss	521	353	6	-	57	42	584	395
Accrued benefit asset	80	97	-	-	42	30	122	127

Pension assets are valued at market rates and are invested as follows:

	MH Pension Fund Fair value		Centra curtailed pension plans Fair value	
	2013	2012	2013	2012
	millions of dollars			
Equities	492	495	63	57
Bonds and debentures	185	181	23	22
Real estate	89	79	8	4
Infrastructure	22	-	3	-
Short-term investments	4	3	-	1
	792	758	97	84

Manitoba Hydro has $14 million (2012 - $11 million) on deposit with the CSSB for the EHBP. Manitoba Hydro does not have a separate portfolio of assets for the EHBP. The investment income earned on the EHBP funds is based on the market value rate of return that is earned by the Civil Service Superannuation Fund (CSSF). For the year ended December 31, 2012, the CSSF earned a rate of return of 10.23% on fund assets.

The return on pension fund assets for the MH Pension Fund was 7.5% (2012 - 2.1%). The return for the Centra curtailed plan fund assets was 7.3% (2012 - 2.0%). The weighted average term to maturity on fixed income investments is 8.9 years (2012 - 9.5 years).

The most recent actuarial valuations for the Corporation's obligations under the CSSB and Centra curtailed pension plans were performed with respect to the liabilities outstanding as at December 31, 2012. These valuations incorporated management's best estimate assumptions and took into consideration the long-term nature of the pension plans. The next actuarial valuations for all plans, including the EHBP will occur in December 2013. The Centra curtailed pension plans are also subject to a solvency valuation for funding purposes with the latest valuation taking place as at December 31, 2012.

The significant actuarial assumptions adopted in measuring the Corporation's pension and other employee benefit obligations are as follows:

	2013	2012
Discount rate - pensions	4.25%	5.25%
Discount rate - other benefits	4.25%	5.50%
Expected long-term rate of return on plan assets	7.0%	7.0%
Rate of compensation increase, including merit and promotions	1.5 - 2.0%	1.5 - 2.0%
Expected average remaining service life of employees - MH Pensions	14 years	14 years
Expected average remaining service life of employees - Centra Pensions	10 years	10 years
Long-term inflation rate	2.0%	2.0%

The Corporation's pension expense related to each of the pension benefit plans is as follows:

	CSSB Plan		Enhanced Hydro Benefit Plan		Centra curtailed pension plans	
	2013	2012	2013	2012	2013	2012
	millions of dollars					
Current service cost	35	27	2	2	-	-
Administrative fees	2	2	-	-	-	-
Canada Pension Plan	15	14	-	-	-	-
Interest on obligation	53	54	1	-	5	6
Expected return on plan assets	(58)	(58)	(1)	-	(7)	(6)
Amortization of net experience loss	13	3	-	-	2	1
Amortization of transitional gain	(1)	(1)	-	-	-	-
	59	41	2	2	-	1

Notes to the Consolidated Financial Statements
For the year ended March 31, 2013

Pension expense for the former Winnipeg Hydro employees is equal to employer contributions to the WCEBP in addition to employer remittances to the Canada Pension Plan. Total contributions to the WCEBP during the year amounted to $1 million (2012 - $1 million) and reflect an employer contribution rate approximating 3.8% of pensionable earnings to January 2, 2013 and 4.3% of pensionable earnings thereafter. Pension expense for MHUS and MHI is equal to the employer contributions and is expensed during the period. The amounts are not material.

Manitoba Hydro also provides some non-pension employee future benefits including banked incidental and vacation days, long-term disability, retiree health spending, sick leave vesting and severance.

The following table presents information concerning other employee future benefits:

	2013	2012
	millions of dollars	
Accrued benefit liability		
Balance at beginning of year	173	166
Interest on obligation	9	7
Current service cost	23	21
Benefit payments	(17)	(18)
Transfers to EHBP	-	(9)
Actuarial loss	13	6
	201	173
Unamortized past service costs	(7)	(8)
Unamortized transitional obligation	(3)	(3)
Unamortized net actuarial loss	(17)	(6)
Accrued benefit liability	174	156

NOTE 19 COMMITMENTS AND CONTINGENCIES

Manitoba Hydro has energy purchase commitments of $1 592 million (2012 - $1 651 million) that relate to future purchases of wind, natural gas (including transportation and storage contracts), coal and electricity. Commitments are primarily for wind, which expire in 2038, and natural gas purchases, which expire in 2020. In addition, other outstanding commitments principally for construction, are approximately $1 592 million (2012 - $771 million).

The Corporation will incur future costs associated with the assessment and remediation of contaminated lands and facilities and for the phase-out and destruction of polychlorinated biphenyl contaminated mineral oil from electrical equipment. Although these costs cannot be reasonably determined at this time (except for items already recognized as asset retirement obligations), a contingent liability exists.

Due to the size, complexity and nature of Manitoba Hydro's operations, various legal and operational matters are pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have a material effect on Manitoba Hydro's consolidated financial position or results of operations.

Manitoba Hydro provides guarantees to counterparties as part of its use of natural gas derivative commodity contracts. Guarantees issued at March 31, 2013 totaled $289 million (2012 - $305 million) and do not have specific maturity dates. Letters of credit in the amount of $6 million (2012 - $10 million) have been issued for energy related transactions with maturities until 2014.

NOTE 20 MITIGATION

Manitoba Hydro's mitigation program addresses past, present and ongoing adverse effects of hydro-electric development. The mitigation program, established in the late 1970s to address project impacts through alleviation of adverse effects, remedial works, offsetting programs and residual monetary compensation, grew out of the experience of planning and development of the Lake Winnipeg Regulation and Churchill River Diversion Projects. The Northern Flood Agreement, signed December 16, 1977, created a process that addressed ongoing mitigation and compensation for adverse effects of hydro-electric development in five signatory First Nation communities (Nelson House, Split Lake, York Landing, Norway House and Cross Lake). The mitigation program continues to address impacts arising from past hydro-electric developments, particularly for Aboriginal people residing or engaged in resource harvesting in the project area and it is essential for operating and future development purposes.

Expenditures recorded or settlements reached to mitigate the impacts of all projects amounted to $21 million during the year (2012 - $113 million). In recognition of future anticipated mitigation payments, the Corporation has recorded a liability of $235 million (2012 - $251 million). To March 31, 2013, $959 million (2012 - $938 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.

Included in mitigation payments or liabilities are obligations assumed on behalf of the Province of Manitoba with respect to certain northern development projects. The Corporation has assumed obligations totaling $146 million for which water power rental charges were fixed until March 31, 2001. The obligations outstanding at March 31, 2013 amounted to $11 million (2012 - $11 million).

NOTE 21 AFFORDABLE ENERGY FUND

In accordance with the provisions of the Winter Heating Cost Control Act, Manitoba Hydro established an Affordable Energy Fund (the Fund) in the initial amount of $35 million for the purpose of providing support for programs and services that:

(a) encourage energy efficiency and conservation;
(b) encourage the use of alternative energy sources, including earth energy; and
(c) facilitate research and development of alternative energy services and innovative energy technologies.

For accounting purposes, the Fund is classified as other long-term assets (Note 11) with an offsetting balance in other long-term liabilities (Note 15). Expenditures of $5 million (2012 - $7 million) during the year were charged to operations with the asset and liability accounts reduced accordingly. As at March 31, 2013, the balance remaining in the Fund amounted to $15 million (2012 - $20 million).

NOTE 22 NON-CONTROLLING INTEREST

Manitoba Hydro has entered into a partnership agreement with Taskinigahp Power Corporation (TPC) to carry on the business of developing, owning and operating the Wuskwatim generating station. TPC is owned beneficially by Nisichawayasihk Cree Nation (NCN). The generating station and associated transmission was placed into service during the 2012-13 year.

The 33% ownership interest of TPC in the WPLP of $95 million (2012 - $100 million) is represented as a non-controlling interest within the equity section of the consolidated balance sheet. TPC's portion of the net loss of the WPLP during 2012-13 is $13 million (2012 – nil) and is recorded as a non-controlling interest in the consolidated statement of income.

In accordance with the partnership agreements, Manitoba Hydro provides debt financing to TPC. As at March 31, 2013, Manitoba Hydro has provided advances to TPC of $91 million (2012 - $91 million). The advances plus interest are repayable by TPC through distributions from the WPLP.

NOTE 23 SEGMENTED INFORMATION

The Corporation operates primarily in two business segments: electricity and gas. Each segment has its own particular economic characteristics and differs in nature, production processes and technology. The electricity segment encompasses the generation, transmission and distribution of electricity as well as subsidiaries providing related energy services. The gas segment represents natural gas supply and distribution activities through the operations of Centra. The Corporate segment represents the costs to acquire Centra and to integrate its operations into those of Manitoba Hydro. These costs are allocated to gas and electricity segments in accordance with the synergies and benefits derived by each of these segments as a result of the acquisition.

The following table contains information related to the operating results, assets, liabilities, contributions in aid of construction and retained earnings by segment:

	Electricity		Gas		Corporate		Total	
	2013	2012	2013	2012	2013	2012	2013	2012
	millions of dollars							
Revenues*	1 733	1 582	147	132	-	-	1 880	1 714
Expenses								
Operating and administrative	469	419	64	62	-	-	533	481
Finance expense	452	385	18	19	19	19	489	423
Depreciation and amortization	394	353	27	26	2	2	423	381
Water rentals and assessments	118	119	-	-	-	-	118	119
Fuel and power purchased	133	146	-	-	-	-	133	146
Capital and other taxes	87	84	18	19	-	-	105	103
Corporate allocation	9	9	12	12	(21)	(21)	-	-
	1 662	1 515	139	138	-	-	1 801	1 653
Net income (loss) before non-controlling interest	71	67	8	(6)	-	-	79	61
Net loss attributable to non-controlling interest	13	-	-	-	-	-	13	-
Net income (loss)	84	67	8	(6)	-	-	92	61
Total assets	13 928	13 203	614	588	-	-	14 542	13 791
Total liabilities	10 848	10 196	418	400	-	-	11 266	10 596
Contributions in aid of construction	307	285	33	33	-	-	340	318
Retained earnings	2 500	2 416	42	34	-	-	2 542	2 450

*Revenues are stated net of cost of gas sold of $182 million (2012 - $197 million) and MHI project costs of $28 million (2012 - $19 million).

NOTE 24 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2012 have been reclassified in order to conform to the presentation adopted in 2013.

Financial Statistics

For the year ended March 31	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
					dollars are in millions					
Revenues										
Electrical:										
Residential	563	492	503	476	463	436	410	387	386	368
General service	778	701	697	669	664	638	614	597	553	550
Extraprovincial	353	363	398	427	623	625	592	827	554	351
Other revenue	39	26	18	11	21	13	11	10	9	11
Gas:										
Residential	174	172	205	222	292	268	258	245	244	235
Commercial / Industrial	149	151	193	225	281	254	244	267	258	252
Transportation	5	5	5	5	5	4	4	3	5	4
Other revenue	1	1	1	2	2	2	2	2	2	3
	2 062	1 911	2 020	2 037	2 351	2 240	2 135	2 338	2 011	1 774
Expenses										
Operating and administrative	533	481	463	440	429	381	381	368	357	339
Finance expense	489	423	425	410	471	440	506	503	502	487
Depreciation and amortization	423	381	393	384	368	349	332	322	311	296
Water rentals and assessments	118	119	120	121	123	124	112	131	111	71
Fuel and power purchased	133	146	106	104	176	134	226	125	135	569
Capital and other taxes	105	103	102	99	87	80	77	77	75	73
Cost of gas sold	182	197	261	316	431	386	379	397	384	375
	1 983	1 850	1 870	1 874	2 085	1 894	2 013	1 923	1 875	2 210
Net income before non-controlling interest	79	61	150	163	266	346	122	415	136	(436)
Net loss attributable to non-controlling interest	13	-	-	-	-	-	-	-	-	-
Net Income	92	61	150	163	266	346	122	415	136	(436)
Assets										
Property, plant and equipment	15 793	13 631	12 967	12 688	12 300	11 884	11 424	11 065	10 748	10 399
Less: Accumulated depreciation	5 252	4 984	4 752	4 612	4 356	4 187	3 924	3 657	3 447	3 241
Construction in progress	1 967	3 150	2 739	2 052	1 438	1 238	878	602	475	378
Sinking fund investments	352	372	282	822	666	718	630	555	562	715
Current and other assets	1 682	1 622	1 646	1 487	1 499	2 113	1 914	1 917	1 614	1 652
	14 542	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952	9 903
Liabilities and Equity										
Long-term debt	9 329	9 101	8 617	8 228	7 668	7 218	6 822	7 051	7 048	7 114
Current and other liabilities	1 937	1 495	1 127	1 328	1 637	2 097	2 380	1 849	1 738	1 781
Contributions in aid of construction	340	318	295	295	296	300	298	297	296	274
Non-controlling interest	95	100	87	62	39	24	15	-	-	-
Retained earnings	2 542	2 450	2 389	2 239	2 076	1 822	1 407	1 285	870	734
Accumulated other comprehensive income	299	327	367	285	(169)	305	-	-	-	-
	14 542	13 791	12 882	12 437	11 547	11 766	10 922	10 482	9 952	9 903
Cash Flows										
Operating activities	589	567	595	589	688	633	443	710	433	(127)
Financing activities	635	725	674	1 124	424	487	227	77	236	753
Investing activities	1 242	1 312	1 373	1 698	1 086	988	788	677	666	650
Financial Indicators										
Equity ratio[1]	25%	26%	27%	27%	23%	27%	20%	19%	15%	13%
Interest coverage[2]	1.15	1.10	1.27	1.32	1.49	1.69	1.23	1.77	1.25	0.17
Capital coverage[3]	1.25	1.13	1.25	1.34	1.77	1.62	1.10	2.28	1.20	(0.32)

[1] Equity ratio represents equity (retained earnings plus accumulated other comprehensive income plus contributions in aid of construction plus non-controlling interest) divided by equity plus debt (long-term debt plus notes payable minus sinking fund investments and temporary investments).

[2] Interest coverage represents net income plus interest on debt divided by interest on debt.

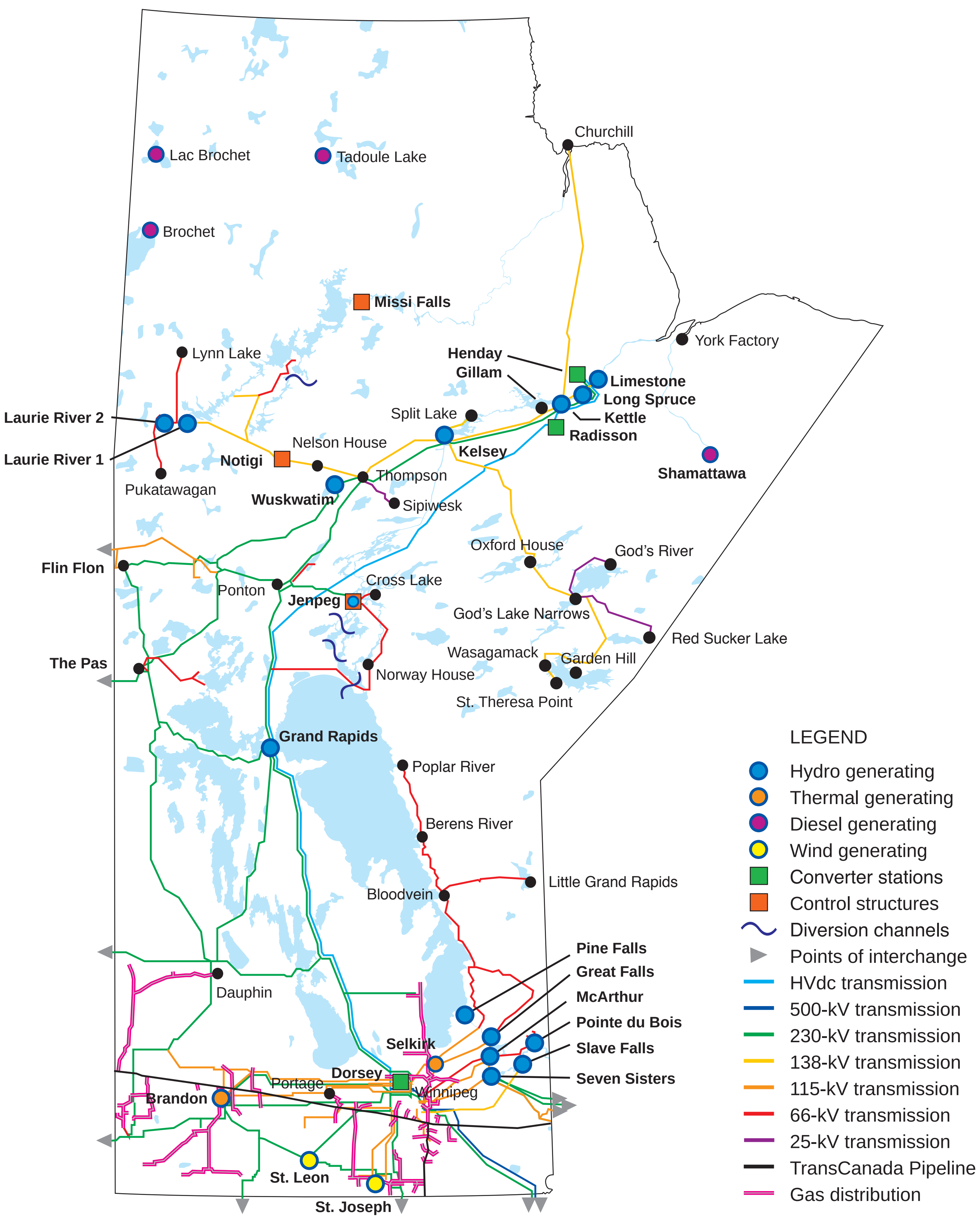
[3] Capital coverage represents internally generated funds divided by capital construction expenditures.

Operating Statistics

For the year ended March 31	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004
Electric System Capability										
Capability (000 kW)	5 675	5 475	5 489	5 501	5 480	5 465	5 461	5 469	5 470	5 471
Manitoba firm peak demand (000 kW)	4 535	4 343	4 261	4 359	4 477	4 273	4 184	4 054	4 169	3 959
Percent change	4.4	1.9	(2.2)	(2.6)	4.8	2.1	3.2	(2.8)	5.3	1.1
Electric System Supply										
Total energy supplied (millions of kWh)										
Generation	33 230	33 235	34 102	33 961	34 528	35 354	32 132	37 620	31 548	19 338
Isolated systems	14	14	13	13	13	12	12	12	11	11
	33 244	33 249	34 115	33 974	34 541	35 366	32 144	37 632	31 559	19 349
Electric Load at Generation (millions of kWh)										
Integrated system	24 650	23 499	23 783	23 295	24 285	23 985	23 327	22 622	22 452	21 907
Isolated system	14	14	13	13	13	12	12	12	11	11
	24 664	23 513	23 796	23 308	24 298	23 997	23 339	22 634	22 463	21 918
Percent change	4.9	(1.2)	2.1	(4.1)	1.3	2.8	3.1	0.8	2.5	(0.3)
Electric System Deliveries (millions of kWh)										
Energy delivered in Manitoba										
Residential	7 334	6 930	7 060	6 899	6 954	6 838	6 539	6 266	6 370	6 266
General service	14 143	13 840	13 727	13 587	14 256	14 223	13 965	13 669	13 365	13 014
	21 477	20 770	20 787	20 486	21 210	21 061	20 504	19 935	19 735	19 280
Extraprovincial	9 087	10 244	10 344	10 860	10 122	11 086	10 100	13 773	10 475	6 966
	30 564	31 014	31 131	31 346	31 332	32 147	30 604	33 708	30 210	26 246
Gas Deliveries (millions of cubic metres)										
Residential	602	509	591	581	696	682	653	600	681	653
Commercial / Industrial	849	728	821	803	866	856	811	782	917	893
Transportation	598	629	584	619	603	618	592	598	559	577
	2 049	1 866	1 996	2 003	2 165	2 156	2 056	1 980	2 157	2 123
Number of Customers										
Electric:										
Residential	480 254	474 661	469 635	465 055	460 804	455 430	450 823	446 370	442 840	438 953
General service	68 520	68 020	67 664	67 304	66 668	66 169	66 038	63 421	62 826	62 697
	548 774	542 681	537 299	532 359	527 472	521 599	516 861	509 791	505 666	501 650
Gas:										
Residential	244 768	242 813	241 123	239 535	239 597	237 724	236 086	234 108	231 366	229 194
Commercial / Industrial	25 018	24 886	24 838	24 766	23 411	23 435	23 483	23 709	24 559	24 437
	269 786	267 699	265 961	264 301	263 008	261 159	259 569	257 817	255 925	253 631
Full Time Equivalent (FTE)[1]	6 463	6 413	6 394	6 236	6 080	5 841	5 773	5 748	5 682	5 548

[1] Regular FTEs (the straight time hours of work for one employee) for Manitoba Hydro, including subsidiaries.

Major electric and gas facilities



Source of electrical energy generated and imported

Sources of Electrical Energy Generated and Purchased

For the Year Ended March 31, 2013

Nelson River	**75.54 %**
Billion kWh generated	**26.1**
Limestone	24.35 %
Kettle	23.36 %
Long Spruce	19.52 %
Kelsey	6.04 %
Jenpeg	2.27 %
Winnipeg River	**10.47 %**
Billion kWh generated	**3.6**
Seven Sisters	2.89 %
Great Falls	2.45 %
Pine Falls	1.78 %
Pointe du Bois	0.87 %
Slave Falls	1.35 %
McArthur	1.13 %

Saskatchewan River	**6.87 %**
Billion kWh generated	**2.4**
Grand Rapids	6.87 %
Laurie River	**0.15 %**
Billion kWh generated	**0.1**
Laurie River #1	0.07 %
Laurie River #2	0.08 %
Burntwood River	**2.74 %**
Billion kWh generated	**0.9 %**
Wuskwatim	2.74 %

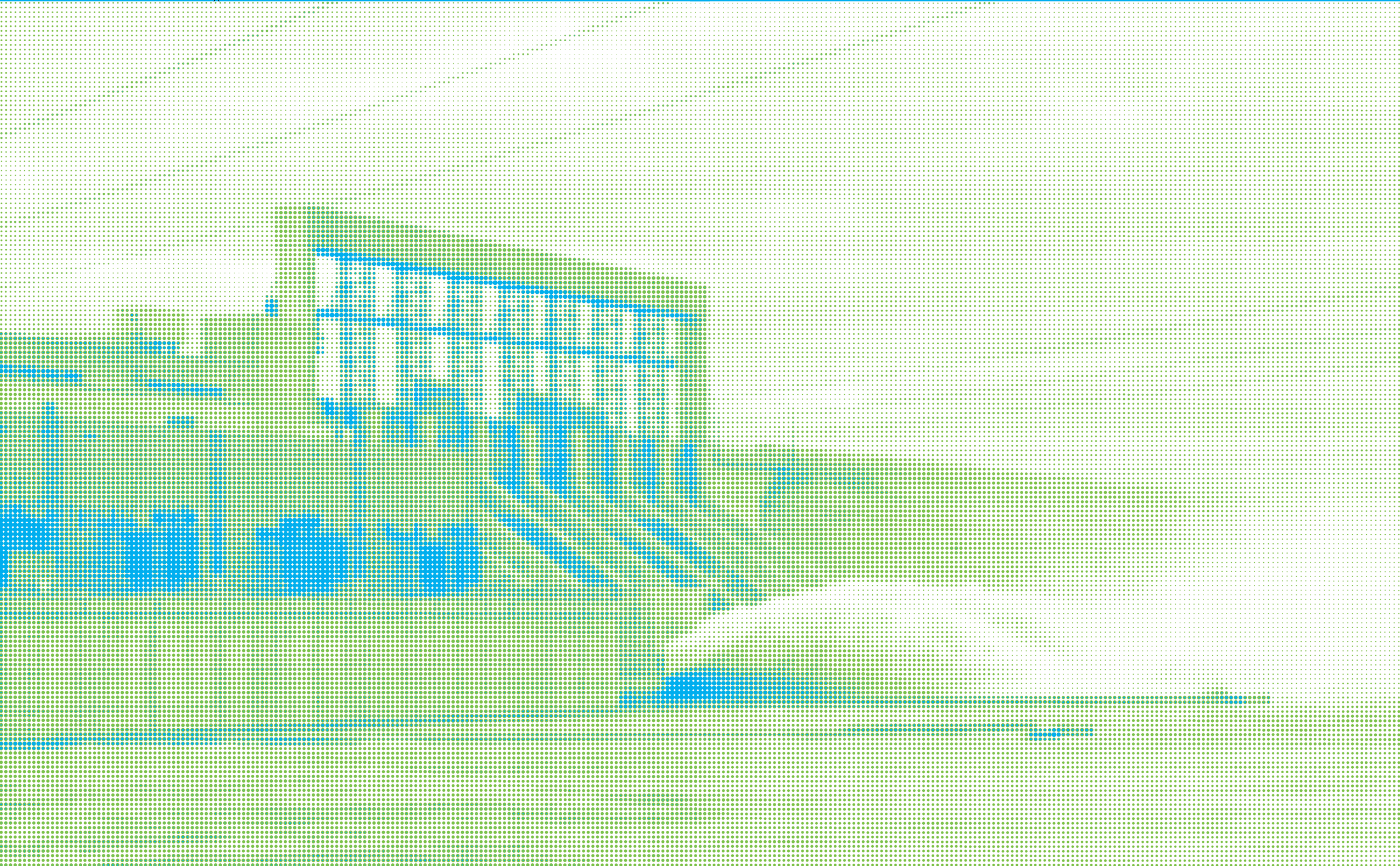
Thermal	**0.24 %**
Billion kWh generated	**0.1**
Brandon	0.19 %
Selkirk	0.05 %
Purchases (excl. wind)	**1.53 %**
Billion kWh purchased	**0.5**
Wind	**2.46 %**
Billion kWh purchased	**0.9**

Manitoba Hydro Generating Stations and Capabilities

For the Year Ended March 31, 2013

Interconnected Capabilities

Station	Location	Number of units	Net Capability (MW)
Hydraulic			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	88
McArthur	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	67
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	250
Kettle	Nelson River	12	1220
Jenpeg	Nelson River	6	129
Long Spruce	Nelson River	10	1010
Limestone	Nelson River	10	1340
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	200
Thermal			
Brandon		3	333
Selkirk		2	125
Isolated Capabilities			
Diesel			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
Total Generating Capability			5 685



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The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the three months ended June 30, 2013

Comments by
THE CHAIR OF THE BOARD
and by
THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro incurred a net loss on consolidated electricity and natural gas operations of $5 million for the first three months of the 2013-14 fiscal year compared to a net loss of $24 million for the same period last year. The $19 million improvement in financial results was largely attributable to increased net extraprovincial revenues resulting from higher sales volumes due to favourable water conditions and higher export prices.

The consolidated net loss was comprised of a $7 million loss in the natural gas sector and a $2 million profit in the electricity sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and should be recouped over the winter heating season.

Based on current water flow and export market conditions, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should reach approximately $70 million by March 31, 2014.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $313 million for the three-month period, which was $20 million or 7% higher than same period last year. The increase in domestic revenue was attributable to electricity rate increases and colder weather as compared to the prior year resulting in higher heating loads. Extraprovincial revenues of $114 million were $27 million or 31% higher than the same period last year reflecting higher sales volumes and higher export prices. Energy sold in the export market was 3.1 billion kilowatt-hours compared to 2.3 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $430 million for the three-month period, an increase of $36 million or 9% higher than the same period last year. The increase was the result of a $15 million increase in finance expense, $8 million increase in depreciation and amortization expense, $5 million increase in fuel and power purchased, $4 million increase in water rentals and assessments, $2 million increase in operating and administrative expenses and a $2 million increase in capital and other taxes. Finance expense increased mainly as a result of the Wuskwatim Generating Station coming into service. Depreciation and amortization expense increased as a result of new additions of plant and equipment coming into service including the Wuskwatim Generating Station. Fuel and power purchased increased due to higher market prices, transmission costs and thermal generation costs. Water rentals increased due to higher hydraulic generation. Operating and administrative expenses increased due to higher pension and benefit costs related to a change in the discount rate. Capital and Other taxes increased mainly due to higher capital taxes related to additional capital investment.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first three months of the 2013-14 fiscal year.

Capital expenditures for the three-month period amounted to $277 million compared to $227 million for the same period last year. Expenditures during the current period included $56 million for the Pointe du Bois projects, $55 million related to future Keeyask and Conawapa generation, $32 million for Bipole III projects, $21 million for the Riel Station, $16 million for Wuskwatim Generating Station and $6 million for demand-side management programs. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province.

Natural Gas Operations

In the natural gas sector, a net loss of $7 million was incurred for the three-month period, compared to the net loss of $10 million in the same period last year. Revenue, net of cost of gas sold, was $29 million which was $4 million higher than the same period last year. The increase in revenues was primarily attributable to increased weather-related demand over the three-month period. Delivered gas volumes were 400 million cubic metres compared to 326 million cubic metres in the prior period.

Expenses attributable to natural gas operations amounted to $36 million compared to $35 million for the same period last year.

Capital expenditures in the natural gas sector were $10 million for the current three-month period compared to $8 million for the same period last year. Capital expenditures included $8 million related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province and $2 million related to demand-side management programs.

Clean Environment Commission Recommends Bipole III Proceed

The Clean Environment Commission (CEC) released its report in early July of 2013 recommending that the environmental license for the Bipole III Transmission Project be approved. In March of 2013, the CEC concluded 35 days of hearings over five months to review the project's environmental impact statement as well as a supplemental filing on four proposed route adjustments. The Minister of Conservation and Water Stewardship will now consider the CEC recommendation in deciding whether to issue a final environmental license for the project.

The Bipole III Transmission Project includes a 1,384 kilometre, 500-kilovolt direct current transmission line, the Keewatinoow Converter Station near the site of the proposed Conawapa Generating Station downstream of Gillam and the Riel Converter Station on the east side of Winnipeg. The project is required to improve system reliability and will also provide additional capacity for delivery of existing and proposed hydroelectric generation to southern markets. The target in-service date for the project is late 2017.

Electricity Rate Increase

Electricity rates for all customer classes increased by approximately 3.5% effective May 1, 2013. The Public Utilities Board directed that 2.0% of the 3.5% increase be included in general revenues and that 1.5% of the increase be used to mitigate rate increases when Bipole III comes into service.

The rate increase was necessary to partially offset the financial impacts of lower revenue due to economic conditions, lower prices in export markets and to provide sufficient revenues for the Corporation to meet its ongoing cost of operations and support ongoing reliability of electricity services. Even with the rate increase, electricity customers in Manitoba continue to benefit from the lowest electricity rate structure in North America.

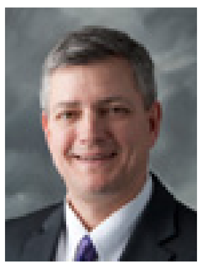
Natural Gas Rate Increase

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers increased on May 1, 2013 by 5.6% or approximately $42 per year. Rate increases for larger volume customers ranged from 6.5% to 13.0% depending on the customer class and consumption levels. The May 1, 2013 rate change was the first quarterly gas rate increase since August 1, 2012.

Manitoba Hydro named one of Canada's Greenest Employers

Manitoba Hydro received an award on Earth Day (April 22) as one of Canada's Greenest Employers. Canada's Greenest Employers competition recognizes employers that lead the nation in incorporating environmental awareness into their organizational cultures. Manitoba Hydro was recognized for several reasons including its state-of-the-art climatically responsive head office building, its environmental management system which is designed to ensure the Corporation addresses the environmental impacts of ongoing and future operations, being a power producer with virtually all electricity coming from self renewing water power generation, its promotion of classroom education and sustainable development in partnership with Manitoba Education and its participation in the annual commuter challenge with over 800 employees participating.

William Fraser, FCA
The Chair of the Board



Scott Thomson, CA
President and
Chief Executive Officer
August 15, 2013

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30 2013	Three Months Ended June 30 2012
Revenues		
Electric – Manitoba	313	293
– Extraprovincial	114	87
Gas – Commodity	32	22
– Distribution	29	25
	488	427
Cost of gas sold	32	22
	456	405
Expenses		
Operating and administrative	135	131
Finance expense	125	111
Depreciation and amortization	110	102
Water rentals and assessments	30	26
Fuel and power purchased	37	32
Capital and other taxes	29	27
	466	429
Net Loss before non-controlling interest	(10)	(24)
Net Loss attributable to non-controlling interest	5	-
Net Loss	(5)	(24)

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at June 30 2013	As at June 30 2012
Assets		
Capital assets	12 707	11 953
Current assets	551	591
Other assets	1 120	1 120
	14 378	13 664
Liabilities and Equity		
Long-term debt (net)	8 936	9 041
Current liabilities	1 474	717
Other liabilities	773	761
Contributions in aid of construction	346	324
Non-controlling interest	90	103
Retained earnings	2 537	2 426
Accumulated other comprehensive income	222	292
	14 378	13 664

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2013	**2012**
Operating Activities		
Cash receipts from customers	574	496
Cash paid to suppliers and employees	(289)	(295)
Net interest	(150)	(131)
	135	70
Financing Activities	188	247
Investing Activities	(333)	(244)
Net increase in cash	(10)	73
Cash at beginning of period	32	50
Cash at end of period	22	123

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2013	**2012**
Net Loss	(5)	(24)
Other Comprehensive Loss		
Unrealized foreign exchange losses on debt in cash flow hedges	(71)	(39)
Unrealized fair value (losses) gains on available-for-sale U.S. sinking fund investments	(6)	4
	(77)	(35)
Comprehensive Loss	(82)	(59)

Segmented Information

In Millions of Dollars (Unaudited)

Three Months Ended	Electricity		Gas		Total	
June 30	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue (net of cost of gas sold)	427	380	29	25	456	405
Expenses	430	394	36	35	466	429
Net Loss before non-controlling interest	(3)	(14)	(7)	(10)	(10)	(24)
Net Loss attributable to non-controlling interest	5	-	-	-	5	-
Net Income (Loss)	2	(14)	(7)	(10)	(5)	(24)
Total Assets	13 778	13 096	600	568	14 378	13 664

Generation and Delivery Statistics

	Three Months Ended June 30	
	2013	**2012**
Electricity in gigawatt-hours		
Hydraulic generation	8 536	7 257
Thermal generation	24	5
Scheduled energy imports	38	124
Wind purchases (MB)	228	218
Total system supply	8 826	7 604
Gas in millions of cubic metres		
Gas sales	201	149
Gas transportation	199	177
	400	326

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Manitoba Hydro

Cover: *Manitoba Hydro's 500-kilovolt transmission line runs from Dorsey Converter Station, located northwest of Winnipeg, to Forbes Station in Minnesota.*

The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the six months ended September 30, 2013

Comments by

THE CHAIR OF THE BOARD

and by

THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro incurred a net loss on consolidated electricity and natural gas operations of $2 million for the first six months of the 2013-14 fiscal year compared to a net loss of $43 million for the same period last year. The $41 million improvement in financial results was attributable to increased revenues from extraprovincial and domestic electricity sales, partially offset by higher costs of operations.

The consolidated net loss was comprised of a $21 million loss in the natural gas sector and a $19 million profit in the electricity sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $100 million by March 31, 2014.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $606 million for the six-month period, which was $31 million or 5% higher than same period last year. The increase in domestic revenue was attributable to electricity rate increases, colder weather as compared to the prior year resulting in higher heating loads and more customers, partially offset by a decrease in the average use of customers. Extraprovincial revenues of $245 million were $38 million or 18% higher than the same period last year primarily due to higher sales volumes reflecting favourable water conditions and higher export prices. Energy sold in the export market was 7.1 billion kilowatt-hours compared to 6.0 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $843 million for the six-month period, an increase of $41 million or 5% higher than the same period last year. The increase was the result of a $15 million increase in depreciation and amortization expense, $9 million increase in fuel and power purchased, $6 million increase in water rentals and assessments, $6 million increase in operating and administrative expenses and a $5 million increase in capital and other taxes. Depreciation and amortization expense increased as a result of new additions of plant and equipment coming into service including the Wuskwatim Generating Station. Fuel and power purchased increased due to higher market prices, transmission costs and thermal generation costs partially offset by lower volumes purchased due to higher hydraulic generation. Water rentals and assessments increased due to higher hydraulic generation. Operating and administrative expenses increased due to higher pension and benefit costs related to a change in the discount rate. Capital and other taxes increased mainly due to higher capital taxes related to additional capital investment.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first six months of the 2013-14 fiscal year.

Capital expenditures for the six-month period amounted to $645 million compared to $484 million for the same period last year. Expenditures during the current period included $157 million related to future Keeyask and Conawapa generation, $126 million for the Pointe du Bois projects, $75 million for Bipole III projects, $45 million for the Riel Station, $20 million for Wuskwatim Generating Station and $11 million for demand-side management programs. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province.

Natural Gas Operations

In the natural gas sector, a net loss of $21 million was incurred for the six-month period, compared to the net loss of $25 million in the same period last year. Revenue, net of cost of gas sold, was $49 million which was $4 million higher than the same period last year. The increase in revenues was primarily attributable to increased weather-related demand over the six-month period. Delivered gas volumes were 643 million cubic metres compared to 534 million cubic metres in the prior period.

Expenses attributable to natural gas operations amounted to $70 million which was consistent with the same period last year.

Capital expenditures in the natural gas sector were $20 million for the current six-month period compared to $18 million for the same period last year. Capital expenditures included $17 million related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province and $3 million related to demand-side management programs.

Manitoba Hydro Files NFAT Submission with Public Utilities Board

On August 16, Manitoba Hydro filed its Needs For and Alternatives To (NFAT) submission with the Manitoba Public Utilities Board (PUB). The submission details Manitoba Hydro's Preferred Development Plan for meeting the province's growing electricity needs, with new sources of generation required by about 2023 to supply Manitobans.

The Preferred Development Plan includes a construction start for the 695-megawatt Keeyask Generating Station in June 2014 for a 2019 in-service date, and construction of the 1 485-megawatt Conawapa Generating Station for a 2026 in-service date. It also includes construction of domestic transmission facilities associated with Keeyask and Conawapa and construction of a new transmission line to the U.S. to provide additional capacity for new export sales and imports during droughts, enhancing reliability of supply to Manitobans and expansion of electricity exports.

The submission provides a detailed and comprehensive review of future options for meeting Manitoba's electricity demand including 15 different plans over 27 scenarios involving more than 400 cases. Alternative supply options examined included increased energy conservation, natural gas, wind, improvements to existing generation, imports and new hydro power.

The submission concludes that Manitoba Hydro should proceed with the Preferred Development Plan because it provides lower long-term rates for Manitobans, greater reliability and security of supply, superior environmental and socio-economic benefits and job creation for the province compared to other options and alternatives. The Preferred Development Plan has the flexibility to accommodate modifications should future conditions suggest that it is prudent to do so. In particular, the timing of Conawapa will be regularly reviewed until the construction start scheduled for 2018.

The PUB will conduct an independent public review of the NFAT submission as requested by the Manitoba government and will provide a report including recommendations on the needs for the Preferred Development Plan and an overall assessment as to whether or not the plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives. The PUB will hold public hearings on the plan in the winter-spring of 2014 and will issue a report to the Manitoba government by June 2014.

Province Issues Licence for Bipole III

On August 14, the Minister of Conservation and Water Stewardship issued the Environment Act Licence for Bipole III. The licence is for the construction, operation and maintenance of the Bipole III Transmission Project. The project consists of a new 500-kilovolt (kV) HVdc transmission line, which connects two new converter stations, two new ground electrodes which connect to each of the new converter stations and new 230-kV ac transmission collector lines to connect the new northern converter station to existing northern converter stations.

Bipole III is required to improve system reliability and will also provide additional capacity for delivery of existing and proposed hydroelectric generation to southern markets. The target in-service date for the project is late 2017.

Natural Gas Rate Changes

Manitoba Hydro's natural gas rates changed effective August 1, 2013. The annual bill for the typical residential customer decreased by approximately 0.2%, or $2 per year, as a result of the rate changes. For larger volume customers, annualized bill impacts range from a decrease of 10.8% to an increase of 0.2% depending on the rate class and level of consumption.

The bill impacts are the net result of reductions in the price that Manitoba Hydro pays for gas from Alberta, partially offset by an approximate 1% increase in general revenues required as a result of higher costs to operate the natural gas utility. The portion of natural gas rates associated with utility operating costs is adjusted periodically through general rate applications with the last such change occurring on May 1, 2010.

William Fraser, FCA
The Chair of the Board

Scott Thomson, CA
President and
Chief Executive Officer
November 15, 2013

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Revenues				
Electric – Manitoba	606	575	293	282
– Extraprovincial	245	207	131	120
Gas – Commodity	45	34	13	12
– Distribution	49	45	20	20
	945	861	457	434
Cost of gas sold	45	34	13	12
	900	827	444	422
Expenses				
Operating and administrative	273	266	138	135
Finance expense	229	230	104	119
Depreciation and amortization	222	207	112	105
Water rentals and assessments	63	57	33	31
Fuel and power purchased	68	59	31	27
Capital and other taxes	58	53	29	26
	913	872	447	443
Net Loss before non-controlling interest	(13)	(45)	(3)	(21)
Net Loss attributable to non-controlling interest	11	2	6	2
Net Income (Loss)	(2)	(43)	3	(19)

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at September 30	As at September 30
	2013	**2012**
Assets		
Capital assets	13 000	12 124
Current assets	516	767
Other assets	1 105	1 131
	14 621	14 022
Liabilities and Equity		
Long-term debt (net)	9 419	9 103
Current liabilities	1 220	983
Other liabilities	765	742
Contributions in aid of construction	355	325
Non-controlling interest	84	103
Retained earnings	2 540	2 407
Accumulated other comprehensive income	238	359
	14 621	14 022

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Operating Activities				
Cash receipts from customers	1 088	925	514	429
Cash paid to suppliers and employees	(503)	(498)	(214)	(203)
Net interest	(346)	(250)	(196)	(119)
	239	177	104	107
Financing Activities	568	636	380	389
Investing Activities	(781)	(536)	(448)	(292)
Net increase in cash	26	277	36	204
Cash at beginning of period	32	50	22	123
Cash at end of period	58	327	58	327

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Net Income (Loss)	(2)	(43)	3	(19)
Other Comprehensive Income (Loss)				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(25)	29	40	68
Realized foreign exchange gains on debt in cash flow hedges reclassified to income	(14)	-	(8)	-
Unrealized fair value gains (losses) on available-for-sale U.S. sinking fund investments	(9)	3	(3)	(1)
Realized gains on redemption of U.S. sinking fund investments	(13)	-	(13)	-
	(61)	32	16	67
Comprehensive Income (Loss)	(63)	(11)	19	48

Segmented Information

In Millions of Dollars (Unaudited)

Six Months Ended	**Electricity**		**Gas**		**Total**	
September 30	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue (net of cost of gas sold)	851	782	49	45	900	827
Expenses	843	802	70	70	913	872
Net Income (Loss) before non-controlling interest	8	(20)	(21)	(25)	(13)	(45)
Net Income attributable to non-controlling interest	11	2	-	-	11	2
Net Income (Loss)	19	(18)	(21)	(25)	(2)	(43)
Three Months Ended						
September 30						
Revenue (net of cost of gas sold)	424	402	20	20	444	422
Expenses	413	408	34	35	447	443
Net Income (Loss) before non-controlling interest	11	(6)	(14)	(15)	(3)	(21)
Net Income attributable to non-controlling interest	6	2	-	-	6	2
Net Income (Loss)	17	(4)	(14)	(15)	3	(19)
Total Assets	14 026	13 443	595	579	14 621	14 022

Generation and Delivery Statistics

	Six Months Ended September 30		*Three Months Ended September 30*	
	2013	**2012**	**2013**	**2012**
Electricity in gigawatt-hours				
Hydraulic generation	17 725	16 285	9 189	9 029
Thermal generation	44	32	20	27
Scheduled energy imports	77	128	39	4
Wind purchases (MB)	382	400	154	182
Total system supply	18 228	16 845	9 402	9 242
Gas in millions of cubic metres				
Gas sales	277	231	76	82
Gas transportation	366	303	167	126
	643	534	243	208

For further information contact:

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PO Box 815 STN Main
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Telephone: 1-204-360-3233

Manitoba Hydro

Cover: The Pinawa Channel of the Winnipeg River was one of the earliest sources of hydroelectricity in Manitoba.

The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the nine months ended December 31, 2013

Comments by

THE CHAIR OF THE BOARD

and by

THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro's consolidated net income from electricity and natural gas operations was $72 million for the first nine months of the 2013-14 fiscal year compared to a net loss of $38 million for the same period last year. The improvement in financial results was attributable to increased revenues from domestic and extraprovincial electricity sales, partially offset by higher costs of operations.

The consolidated net income was comprised of a $78 million profit in the electricity sector and a $6 million loss in the natural gas sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $130 million by March 31, 2014.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $990 million for the nine-month period, which was $84 million or 9% higher than the same period last year. The increase in domestic revenue was attributable to electricity rate increases, colder weather as compared to the prior year resulting in higher heating loads and more customers, partially offset by a decrease in the average use of customers. Extraprovincial revenues of $338 million were $58 million or 21% higher than the same period last year primarily due to higher sales volumes reflecting favourable water conditions and higher export prices. Energy sold in the export market was 9.2 billion kilowatt-hours compared to 7.6 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $1 267 million for the nine-month period, an increase of $49 million or 4% higher than the same period last year. The increase was the result of a $19 million increase in operating and administrative expenses, $18 million increase in depreciation and amortization expense, $9 million increase in fuel and power purchased, $8 million increase in water rentals and assessments and a $5 million increase in capital and other taxes. This was partially offset by a $10 million decrease in finance expense. Operating and administrative expenses increased due to higher pension and benefit costs primarily related to a change in the discount rate. Depreciation and amortization expense increased as a result of new additions of plant and equipment coming into service including the Wuskwatim Generating Station. Fuel and power purchased increased due to higher market prices and transmission costs. Water rentals and assessments increased due to higher hydraulic generation. Capital and other taxes increased mainly due to higher capital taxes as a result of additional capital investment. Finance expense decreased primarily due to the gain resulting from the sale of sinking fund investments related to the maturity of debt issues.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first nine months of the 2013-14 fiscal year.

Capital expenditures for the nine-month period amounted to $1 056 million compared to $733 million for the same period last year. Expenditures during the current period included $240 million related to future Keeyask and Conawapa generation, $201 million for the Pointe du Bois projects, $125 million for Bipole III projects, $61 million for the Riel Station and $19 million for demand-side management programs. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province.

Natural Gas Operations

In the natural gas sector, a net loss of $6 million was incurred for the nine-month period, compared to the net loss of $14 million in the same period last year. Revenue, net of cost of gas sold, was $99 million which was $8 million higher than the same period last year. The increase in revenues was primarily attributable to increased weather-related demand over the nine-month period. Delivered gas volumes were 1 362 million cubic metres compared to 1 207 million cubic metres in the prior period.

Expenses attributable to natural gas operations amounted to $105 million which was consistent with the same period last year.

Capital expenditures in the natural gas sector were $32 million for the current nine-month period compared to $29 million for the same period last year. Capital expenditures included $26 million related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province and $6 million related to demand-side management programs.

Keeyask Clean Environment Commission Hearings

The Clean Environment Commission (CEC) began public hearings to review the Keeyask Generating Station project's environmental impact statement and supplemental information on September 24, 2013. The public hearing was completed in January of 2014 and the CEC will file a report with the Minister of Conservation and Water Stewardship that outlines the results of its review and provides recommendations for the Minister's consideration.

The $6.2 billion, 695-megawatt (MW) Keeyask Generating station is being developed by Manitoba Hydro in partnership with the four Keeyask Cree Nations, Tataskweyak Cree Nation, War Lake First Nation, Fox Lake First Nation and York Factory First Nation. Pending regulatory approvals, construction is expected to commence later in 2014 for a planned in-service date of 2019.

New Power Sale to Saskatchewan

Manitoba Hydro has reached an agreement with SaskPower to sell an additional $100 million of electricity over the next eight years. This is the single-largest power sale agreement between Manitoba and Saskatchewan. Manitoba Hydro and SaskPower also announced they have signed a memorandum of understanding on a potential 500-MW sale which would commence after 2020.

New Agreement with Great River Energy

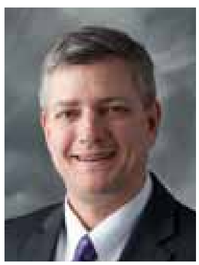
Manitoba Hydro has signed a 200-MW seasonal diversity exchange with Great River Energy of Minnesota, extending an existing 150-MW arrangement that has been in place between the two utilities since 1995. The new agreement will run until 2030.

Seasonal diversity exchanges take advantage of the fact that Manitoba Hydro's load peaks during winter, due to the demand for heating, while most U.S. utilities like Great River Energy experience their peak loads in the summer, due to higher air conditioning use. The diversity exchange means Manitoba Hydro will provide 200-MW of renewable hydroelectric capacity to Great River Energy in the summer to meet their energy needs, while Great River Energy will provide Manitoba Hydro with 200-MW of capacity during the winter. This is a good mechanism for both utilities to share capacity and diversify sources of supply.

Natural Gas Rate Increase

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers increased on November 1, 2013 by 1.4% or approximately $11 per year. Rate increases for larger volume customers ranged from 1.6% to 3.2% depending on the customer class and consumption levels. The bill impacts are the result of an increase in the price that Manitoba Hydro pays for gas from Alberta.

William Fraser, FCA
The Chair of the Board



Scott Thomson, CA
President and
Chief Executive Officer
February 12, 2014

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2013	**2012**	**2013**	**2012**
Revenues				
Electric – Manitoba	990	906	384	331
– Extraprovincial	338	280	93	73
Gas – Commodity	126	98	81	64
– Distribution	99	91	50	46
	1 553	1 375	608	514
Cost of gas sold	126	98	81	64
	1 427	1 277	527	450
Expenses				
Operating and administrative	405	384	132	118
Finance expense	349	361	120	131
Depreciation and amortization	334	316	112	109
Water rentals and assessments	95	87	32	30
Fuel and power purchased	105	96	37	37
Capital and other taxes	84	79	26	26
	1 372	1 323	459	451
Net Income (Loss) before non-controlling interest	55	(46)	68	(1)
Net Loss attributable to non-controlling interest	17	8	6	6
Net Income (Loss)	72	(38)	74	5

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at December 31	As at December 31
	2013	**2012**
Assets		
Capital assets	13 323	12 297
Current assets	798	614
Other assets	1 100	1 130
	15 221	14 041
Liabilities and Equity		
Long-term debt (net)	10 187	8 886
Current liabilities	978	1 227
Other liabilities	825	750
Contributions in aid of construction	369	328
Non-controlling interest	78	99
Retained earnings	2 613	2 412
Accumulated other comprehensive income	171	339
	15 221	14 041

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2013	**2012**	**2013**	**2012**
Operating Activities				
Cash receipts from customers	1 614	1 384	526	459
Cash paid to suppliers and employees	(728)	(741)	(225)	(243)
Net interest	(434)	(299)	(88)	(49)
	452	344	213	167
Financing Activities	1 082	581	514	(55)
Investing Activities	(1 289)	(838)	(508)	(302)
Net increase (decrease) in cash	245	87	219	(190)
Cash at beginning of period	32	50	58	327
Cash at end of period	277	137	277	137

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2013	**2012**	**2013**	**2012**
Net Income (Loss)	72	(38)	74	5
Other Comprehensive Income (Loss)				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(85)	8	(60)	(21)
Realized foreign exchange losses (gains) on debt in cash flow hedges reclassified to income	(20)	1	(6)	1
Unrealized fair value gains (losses) on available-for-sale U.S. sinking fund investments	(11)	3	(2)	-
Realized gains on redemption of U.S. sinking fund investments	(13)	-	-	-
	(129)	12	(68)	(20)
Comprehensive Income (Loss)	(57)	(26)	6	(15)

Segmented Information

In Millions of Dollars (Unaudited)

Nine Months Ended December 31	**Electricity 2013**	**Electricity 2012**	**Gas 2013**	**Gas 2012**	**Total 2013**	**Total 2012**
Revenue (net of cost of gas sold)	1 328	1 186	99	91	1 427	1 277
Expenses	1 267	1 218	105	105	1 372	1 323
Net Income (Loss) before non-controlling interest	61	(32)	(6)	(14)	55	(46)
Net Loss attributable to non-controlling interest	17	8	-	-	17	8
Net Income (Loss)	78	(24)	(6)	(14)	72	(38)
Three Months Ended December 31						
Revenue (net of cost of gas sold)	477	404	50	46	527	450
Expenses	424	416	35	35	459	451
Net Income (Loss) before non-controlling interest	53	(12)	15	11	68	(1)
Net Loss attributable to non-controlling interest	6	6	-	-	6	6
Net Income (Loss)	59	(6)	15	11	74	5
Total Assets	14 578	13 425	643	616	15 221	14 041

Generation and Delivery Statistics

	Nine Months Ended December 31		*Three Months Ended December 31*	
	2013	**2012**	**2013**	**2012**
Electricity in gigawatt-hours				
Hydraulic generation	26 715	24 421	8 990	8 136
Thermal generation	80	72	36	40
Scheduled energy imports	212	335	135	207
Wind purchases (MB)	639	622	257	222
Total system supply	27 646	25 450	9 418	8 605
Gas in millions of cubic metres				
Gas sales	767	680	490	449
Gas transportation	595	527	229	224
	1 362	1 207	719	673

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Manitoba Hydro

Cover: Forty-two Manitoba Hydro employees travelled to Toronto during the 2013 holiday season to help restore power after an ice storm.

The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the nine months ended December 31, 2014

Comments by
THE CHAIR OF THE BOARD

and by
THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

FINANCIAL OVERVIEW

Manitoba Hydro's consolidated net income from electricity and natural gas operations was $42 million for the first nine months of the 2014-15 fiscal year compared to a net income of $72 million for the same period last year. The decrease in net income was primarily attributable to higher financing expenses partially offset by increased revenues from domestic electricity sales.

Consolidated net income was comprised of a $53 million profit in the electricity sector and an $11 million loss in the natural gas sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and is expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions and assuming normal winter weather, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $120 million by March 31, 2015.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $991 million for the nine-month period, which was $27 million or 3% higher than same period last year. The increase in domestic revenue was primarily attributable to electricity rate increases and an increase in customers, partially offset by warmer weather compared to the prior year, which reduced the heating load. Extraprovincial revenues of $318 million were $14 million or 4% lower than the same period last year reflecting lower sales volumes as a result of a U.S. transmission line outage partially offset by favourable foreign exchange rates on U.S. sales. Energy sold in the export market was 8.2 billion kilowatt-hours compared to 9.2 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations totaled $1 322 million for the nine-month period, an increase of $38 million or 3% higher than the same period last year. The increase was the result of a $46 million increase in finance expense, a $10 million increase in fuel and power purchased costs and a $6 million increase in capital and other taxes, partially offset by an $11 million decrease in depreciation and amortization expense, a $9 million decrease in operating and administrative expenses, a $3 million decrease in water rental and assessments and a $1 million decrease in other expenses. Finance expense increased primarily as a result of higher debt levels to finance capital asset additions as well as lower realized foreign exchange gains on U.S. debt and gains on the sale of U.S. sinking fund investments compared to the prior year. Fuel and power purchased increased as a result of higher system merchant costs due to increased arbitrage opportunities between markets and an increase in wind generation purchases. Capital and other taxes increased primarily as a result of higher capital taxes due to additions to capital assets. Depreciation and amortization expense decreased primarily as a result of revised depreciation rates partially offset by the Riel 230 kilovolt (kV) station and the Pointe du Bois spillway coming into service in the current year. Operating and administrative expenses decreased due to a greater focus on capital requirements relating to investment in new and existing infrastructure partially offset by costs required for storm restoration activities.

The net loss attributable to non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first nine months of the 2014-15 fiscal year.

Capital expenditures for the nine-month period amounted to $1 372 million compared to $1 037 million for the same period last year. Expenditures during the current period included $553 million related to future Keeyask generation, $207 million for Bipole III projects, $127 million for Pointe du Bois projects, $31 million for future Conawapa generation and $31 million for the Riel Station. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The Corporation also incurred $23 million for electric demand-side management (DSM) programs.

Natural Gas Operations

In the natural gas sector, a net loss of $11 million was incurred for the nine-month period, compared to the net loss of $6 million in the same period last year. Revenue, net of cost of gas sold, was $97 million which is $2 million lower than the same period last year. The decrease in net revenues was primarily related to warmer weather compared to the prior year which reduced the heating load. Delivered gas volumes were 1 249 million cubic metres compared to 1 362 million cubic metres in the prior year.

Expenses attributable to natural gas operations amounted to $108 million as compared to $105 million for the same period last year. The increase was the result of a $2 million increase in operating and administrative expenses and a $1 million increase in depreciation and amortization expense. Operating and administrative expenses increased due to greater activity in various programs such as customer inspections and distribution maintenance. Depreciation and amortization increased as a result of additions to capital assets.

Capital expenditures in the natural gas sector were $25 million for the current nine-month period compared to $26 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The Corporation also incurred $7 million for gas DSM programs.

New Riel Terminal Station Improves Reliability of Electricity Supply in Manitoba

Enhancements to the reliability and security of Manitoba's electricity supply were made with the completion of Manitoba Hydro's new Riel Terminal Station, located just east of Winnipeg, which was placed in service in October of 2014.

Riel Station will improve the reliability of the transmission system serving Winnipeg and southern Manitoba by providing a second location where electricity imported from the U.S. on an existing 500 kV transmission line can be fed into Manitoba Hydro's power grid. The transmission line to the U.S. is an important component of Manitoba Hydro's system as it delivers surplus electricity for sale to the U.S. and provides access to an alternate supply of energy for import in the event of an emergency or prolonged drought. The 500 kV transmission line runs from Dorsey Converter Station, northwest of Winnipeg, to Minnesota. Construction of Riel Station began after studies concluded it was necessary to reduce dependence on the existing end-point of the line at Dorsey.

Manitoba Hydro Wins Conservation Award for Top Performance in North America

Manitoba Hydro won a prestigious achievement award in October of 2014 for generating energy savings for natural gas customers. Awarded by E Source, an independent U.S. firm that provides research and advisory services to utilities on DSM and improving customer service, Manitoba Hydro was ranked as achieving the highest natural gas savings per customer among 53 utilities across North America.

Customers across Manitoba continue to reap the benefits of Manitoba Hydro's Power Smart* initiatives, such as the Home Insulation Program. The average residential customer participating in the Power Smart Home Insulation Program saves nearly 530 cubic metres in natural gas or $154 on their energy bill per year based on current rates. Total energy savings for Manitoba Hydro's customers last year under this program alone was nearly 717 000 cubic metres, which represents a reduction of over $209 000 in their energy bills.

Customers who heat with electricity also see major savings with the Power Smart Home Insulation Program. The average electrically-heated home saves about 4 300 kilowatt hours per year once they take advantage of this program, which works out to a saving of about $300 annually. In total, participating customers who heat with electricity saved over $327 000 last year.

The E Source award confirms Manitoba Hydro's commitment to aggressive energy conservation. This commitment is being continued through investments in the utility's Power Smart programs that will more than double over the next three years.

By 2017 cumulative energy savings since the inception of Power Smart will equal 905 megawatts of capacity and 3 358 gigawatt hours of electricity — equivalent to about half the current electrical needs of all residential and commercial customers in the city of Winnipeg. Over the same period natural gas use will be reduced by 133 million cubic metres — equivalent to twice the current natural gas needs of Brandon's commercial and residential customers.

Natural Gas Rate Increase

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers increased on November 1, 2014 by 5.0% or approximately $43 per year. Rate changes for larger volume customers ranged from an increase of 3.2% to 12.5% depending on the customer class and consumption levels. The bill impacts are the result of an increase in the price that Manitoba Hydro pays for gas from Alberta as well as the implementation of rate adjustments associated with gas costs that resulted from extreme weather and market circumstances experienced over the 2014 winter.

William Fraser, FCA
Chair of the Board

Scott Thomson, CA
President and
Chief Executive Officer
February 13, 2015

*Manitoba Hydro is a licensee of the Trademark and Official Mark.

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

		Nine Months Ended December 31		Three Months Ended December 31	
		2014	**2013**	**2014**	**2013**
Revenues					
Electric	– Manitoba	991	964	379	375
	– Extraprovincial	318	332	77	90
	– Other	48	49	19	16
Gas	– Commodity	154	126	96	81
	– Distribution	97	99	47	50
		1 608	1 570	618	612
Cost of gas sold		154	126	96	81
		1 454	1 444	522	531
Expenses					
Operating and administrative		398	405	134	132
Finance expense		395	349	137	120
Depreciation and amortization		324	334	96	112
Water rentals and assessments		92	95	30	32
Fuel and power purchased		109	99	43	34
Capital and other taxes		90	84	30	26
Other expenses		22	23	9	7
		1 430	1 389	479	463
Net Income before non-controlling interest		24	55	43	68
Net Loss attributable to non-controlling interest		18	17	5	6
Net Income		42	72	48	74

Consolidated Balance Sheet

In Millions of Dollars (Unaudited)

	As at December 31 **2014**	As at December 31 **2013**
Assets		
Capital assets	14 819	13 323
Current assets	939	798
Other assets	1 190	1 100
	16 948	15 221
Liabilities and Equity		
Long-term debt (net)	11 641	10 187
Current liabilities	1 009	956
Other liabilities	1 006	847
Contributions in aid of construction	420	369
Non-controlling interest	107	78
Retained earnings	2 758	2 613
Accumulated other comprehensive income	7	171
	16 948	15 221

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2014	**2013**	**2014**	**2013**
Operating Activities				
Cash receipts from customers	1 724	1 608	529	520
Cash paid to suppliers and employees	(923)	(723)	(267)	(220)
Net interest	(354)	(327)	(45)	(37)
	447	558	217	263
Financing Activities	1 150	976	265	464
Investing Activities	(1 360)	(1 289)	(410)	(508)
Net increase in cash	237	245	72	219
Cash at beginning of period	142	32	307	58
Cash at end of period	379	277	379	277

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2014	**2013**	**2014**	**2013**
Net Income (Loss)	42	72	48	74
Other Comprehensive Income (Loss)				
Unrealized foreign exchange losses on debt in cash flow hedges	(86)	(85)	(60)	(60)
Realized foreign exchange gains on debt in cash flow hedges reclassified to income	(3)	(20)	(3)	(6)
Unrealized fair value losses on available-for-sale U.S. sinking fund investments	-	(11)	-	(2)
Realized gains on redemption of U.S. sinking fund investments	-	(13)	-	-
	(89)	(129)	(63)	(68)
Comprehensive Income (Loss)	(47)	(57)	(15)	6

Segmented Information

In Millions of Dollars (Unaudited)

Nine Months Ended	Electricity		Gas		Total	
December 31	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Revenue (net of cost of gas sold)	1 357	1 345	97	99	1 454	1 444
Expenses	1 322	1 284	108	105	1 430	1 389
Net Income (Loss) before non-controlling interest	35	61	(11)	(6)	24	55
Net Loss attributable to non-controlling interest	18	17	-	-	18	17
Net Income (Loss)	53	78	(11)	(6)	42	72
Three Months Ended December 31						
Revenue (net of cost of gas sold)	475	481	47	50	522	531
Expenses	443	428	36	35	479	463
Net Income before non-controlling interest	32	53	11	15	43	68
Net Loss attributable to non-controlling interest	5	6	-	-	5	6
Net Income	37	59	11	15	48	74
Total Assets	16 221	14 578	727	643	16 948	15 221

Generation and Delivery Statistics

	Nine Months Ended December 31		*Three Months Ended December 31*	
	2014	**2013**	**2014**	**2013**
Electricity in gigawatt-hours				
Hydraulic generation	25 949	26 715	8 392	8 990
Thermal generation	30	80	14	36
Scheduled energy imports	136	212	97	135
Wind purchase (MB)	698	639	278	257
Total system supply	26 813	27 646	8 781	9 418
Gas in millions of cubic metres				
Gas sales	730	767	447	490
Gas transportation	519	595	206	229
	1 249	1 362	653	719

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Manitoba Hydro

Cover: Recruits at Manitoba Hydro's Stonewall Training Centre.

Financial Information MFR 5

A table, which details the debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings, DBRS bond ratings, total Provincial Debt and total MH debt to total Manitoba debt in each year since 1992.

Please see the table on the following page which shows consolidated information. Information relating to the Province of Manitoba was provided by the Province.

Financial History

	Debt/Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total MH Assets	MH Net Income	Total MH Debt	MH Retained Earnings	DBRS Bond Rating *	Total Province of MB Debt	Total MH Debt to Total MB Debt
2014	76:24	1.35	1.28	15,639	174	10,868	2,716	A (high)	32,629	33.3%
2013	75:25	1.25	1.15	14,542	92	9,985	2,542	A (high)	30,563	32.7%
2012	74:26	1.13	1.10	13,791	61	9,382	2,450	A (high)	28,698	32.7%
2011	73:27	1.25	1.27	12,882	150	8,647	2,389	A (high)	25,617	33.8%
2010	73:27	1.30	1.32	12,437	163	8,538	2,239	A (high)	24,431	34.9%
2009	77:23	1.77	1.48	11,547	266	8,187	2,076	A (high)	22,727	36.0%
2008	73:27	1.62	1.69	11,766	346	7,571	1,822	A (high)	22,056	34.3%
2007	80:20	1.10	1.23	10,922	122	7,227	1,407	A (high)	20,476	35.3%
2006	81:19	2.28	1.77	10,482	415	7,169	1,285	A (high)	19,828	36.2%
2005	85:15	1.20	1.25	9,952	136	7,204	870	A (high)	19,410	37.1%
2004	87:13	(0.32)	0.17	9,903	(436)	7,390	734	A (high)	18,206	40.6%
2003	80:20	1.10	1.14	10,234	71	7,268	1,170	A (high)	17,810	40.8%
2002	77:23	1.67	1.42	10,405	214	7,661	1,302	A	20,682	37.0%
2001	80:20	1.18	1.62	9,966	270	7,464	1,088	A	20,459	36.5%
2000	83:17	1.28	1.35	8,692	152	6,770	818	A	19,878	34.1%
1999	84:16	1.22	1.23	7,866	100	5,883	666	A	18,278	32.2%
1998	86:14	1.13	1.25	7,617	111	5,548	566	A	17,378	31.9%
1997	88:12	1.12	1.23	7,133	101	5,175	455	A	16,886	30.6%
1996	91:09	1.00	1.16	6,737	70	5,284	354	A	16,763	31.5%
1995	92:08	1.00	1.13	6,449	56	5,034	284	A	16,481	30.5%
1994	93:07	n/a	1.16	6,543	70	5,406	228	A	15,670	34.5%
1993	95:05	n/a	0.95	6,025	(24)	4,971	159	A	14,127	35.2%
1992	94:06	n/a	1.04	6,505	18	5,441	183	A	12,776	42.6%

* The DBRS long term credit rating for the period from 1992-2014 is the same for both the Manitoba Hydro-Electric Board and the Province of Manitoba.

Financial Information MFR 6

A table, which details the debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings for each of the years in the 20-year electric IFF.

Please see the following table for the requested information related to electric operations.

Fiscal Year Ended	Debt/ Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt	Retained Earnings
2015	78:22	0.98	1.16	16 993	102	11 854	2 717
2016	82:18	1.02	1.16	18 866	115	14 046	2 778
2017	84:16	0.94	1.07	21 801	59	16 822	2 837
2018	85:15	1.09	1.06	24 961	64	19 747	2 902
2019	86:14	0.88	0.92	26 585	(90)	21 366	2 812
2020	87:13	0.80	0.91	27 668	(116)	22 549	2 696
2021	88:12	0.82	0.86	28 299	(178)	23 194	2 518
2022	89:11	0.94	0.85	27 727	(206)	23 130	2 312
2023	90:10	1.09	0.86	27 788	(187)	23 378	2 126
2024	90:10	1.22	0.91	27 965	(124)	23 672	2 001
2025	90:10	1.27	0.96	27 914	(53)	23 668	1 948
2026	90:10	1.31	0.98	28 063	(24)	23 832	1 924
2027	90:10	1.48	1.06	28 316	84	23 991	2 007
2028	89:11	1.58	1.11	28 533	155	24 044	2 161
2029	88:12	1.70	1.20	28 884	266	24 106	2 427
2030	86:14	1.94	1.30	29 191	400	24 009	2 826
2031	84:16	2.04	1.42	29 030	536	23 292	3 361
2032	81:19	2.20	1.53	29 675	647	23 263	4 008
2033	78:22	2.29	1.61	30 366	725	23 227	4 732
2034	75:25	2.41	1.71	31 189	826	23 221	5 557

<u>Financial Information MFR 7</u>

Details of the determination of each of the financial targets for the last five fiscal years and for each of the years in the 20 year forecast

Please see the following tables for the details of the financial targets for 2009/10-2033/34.

Debt Ratio
Manitoba Hydro (Electric only)
($ millions)

Fiscal Year Ended	**A** Retained Earnings Consolidated	**B** Retained Earnings Gas	**C** Retained Earnings Subs	**D** **(A-B-C)** Retained Earnings	**E** Unamortized Customer Contributions Consolidated	**F** Unamortized Customer Contributions Gas	**G** **(E-F)** Unamortized Customer Contributions	**H** Accumulated Other Comprehensive Income	**I** Non-Contolling Interest	**J** Long-Term Debt	**K** Sinking Fund Investment	**L** Short-Term Debt	**M** Short-Term Investments	**(J-K+L-M)** / **(D+G+H+I+J-K+L-M)** Debt Ratio
2010	2 239	33	16	2 190	295	32	263	285	62	8 241	822	-	174	0.72
2011	2 389	40	21	2 328	295	33	262	367	87	8 350	282	-	70	0.72
2012	2 450	34	26	2 390	318	33	285	327	100	9 084	372	-	50	0.74
2013	2 542	42	32	2 468	340	33	307	299	95	9 690	352	-	32	0.75
2014	2 716	62	39	2 615	381	42	339	96	73	10 563	111	-	142	0.77
2015				2 717			461	94	117	11 717	125	137	-	0.78
2016				2 778			527	(399)	132	13 832	308	214	-	0.82
2017				2 837			595	(409)	164	16 691	475	130	-	0.84
2018				2 902			665	(363)	212	19 564	711	183	-	0.85
2019				2 812			710	(328)	241	21 162	504	204	-	0.86
2020				2 696			691	(278)	258	22 426	538	124	-	0.87
2021				2 518			672	(287)	255	23 170	506	24	-	0.88
2022				2 312			654	(298)	41	23 057	148	73	-	0.89
2023				2 126			690	(305)	42	23 180	236	198	-	0.90
2024				2 001			727	(305)	45	23 473	467	200	-	0.90
2025				1 948			764	(304)	50	23 465	441	204	-	0.90
2026				1 924			802	(304)	52	23 798	608	34	-	0.90
2027				2 007			839	(304)	55	23 991	886	-	14	0.90
2028				2 161			876	(304)	60	23 983	1 177	61	-	0.89
2029				2 427			914	(304)	67	24 106	1 420	-	149	0.88
2030				2 826			952	(304)	77	24 009	1 633	-	328	0.86
2031				3 361			990	(304)	89	23 292	1 254	-	585	0.84
2032				4 008			1 029	(304)	87	23 263	1 539	-	963	0.81
2033				4 732			1 069	(304)	85	23 227	1 818	-	1 390	0.78
2034				5 557			1 109	(304)	82	23 221	2 139	-	1 844	0.75

Calculation of Long-Term Debt for input into Debt:Equity Ratio

	A	B	C	D	E	F	G
			(A-B)			(D-E)	(C+F)
Fiscal Year Ended	MHEB Long-Term Debt	Gas Long-Term Debt	Long-Term Debt	MHEB Current Portion of Long-Term Debt	Gas Current Portion of Long-Term Debt	Current Portion of Long-Term Debt	Long-Term Debt
2010	8 228	297	7 931	310	0	310	8 241
2011	8 617	297	8 320	30	0	30	8 350
2012	9 101	235	8 866	281	63	218	9 084
2013	9 329	295	9 034	656	0	656	9 690
2014	10 460	270	10 190	408	35	373	10 563
2015	11 705	300	11 405	347	35	312	11 717
2016	13 808	310	13 498	334	0	334	13 832
2017	16 681	320	16 361	330	0	330	16 691
2018	18 689	320	18 369	1 195	0	1 195	19 564
2019	21 177	330	20 847	315	0	315	21 162
2020	21 906	330	21 576	850	0	850	22 426
2021	22 792	340	22 452	718	0	718	23 170
2022	22 955	340	22 615	441	0	441	23 057
2023	23 250	360	22 890	310	20	290	23 180
2024	23 441	370	23 071	412	10	402	23 473
2025	23 395	380	23 015	450	0	450	23 465
2026	24 198	400	23 798	0	0	0	23 798
2027	24 401	410	23 991	0	0	0	23 991
2028	24 343	420	23 923	60	0	60	23 983
2029	24 476	440	24 036	70	0	70	24 106
2030	23 749	440	23 309	730	30	700	24 009
2031	23 739	460	23 279	13	0	13	23 292
2032	23 743	480	23 263	0	0	0	23 263
2033	23 737	490	23 247	10	30	(20)	23 227
2034	23 381	500	22 881	360	20	340	23 221

Interest Coverage
Electric
($ millions)

	A	B	C	D	E	F	G	H	I	
				(A-B-C)				**(E-F-G)**		**(D+H+I)/(H+I)**
Fiscal Year Ended	Consolidated Net Income	Gas Net Income	Subs Net Income	**Electric Net Income**	Consolidated Finance Expense	Gas Finance Expense	Gas Corporate Allocation	**Electric Finance Expense**	**Electric Capitalized Interest**	**Electric Interest Coverage**
2010	163	(1)	4	**160**	410	19	12	**379**	**102**	**1.33**
2011	150	7	4	**139**	425	18	12	**395**	**139**	**1.26**
2012	61	(6)	5	**62**	423	19	12	**392**	**171**	**1.11**
2013	92	8	6	**78**	489	18	12	**459**	**141**	**1.13**
2014	174	20	7	**147**	471	16	12	**443**	**142**	**1.25**
2015				**102**				**495**	**146**	**1.16**
2016				**115**				**510**	**207**	**1.16**
2017				**59**				**548**	**316**	**1.07**
2018				**64**				**581**	**437**	**1.06**
2019				**(90)**				**752**	**388**	**0.92**
2020				**(116)**				**887**	**341**	**0.91**
2021				**(178)**				**1 194**	**112**	**0.86**
2022				**(206)**				**1 326**	**12**	**0.85**
2023				**(187)**				**1 334**	**14**	**0.86**
2024				**(124)**				**1 349**	**17**	**0.91**
2025				**(53)**				**1 351**	**20**	**0.96**
2026				**(24)**				**1 348**	**24**	**0.98**
2027				**84**				**1 338**	**25**	**1.06**
2028				**155**				**1 337**	**17**	**1.11**
2029				**266**				**1 321**	**20**	**1.20**
2030				**400**				**1 301**	**20**	**1.30**
2031				**536**				**1 263**	**24**	**1.42**
2032				**647**				**1 197**	**25**	**1.53**
2033				**725**				**1 161**	**27**	**1.61**
2034				**826**				**1 116**	**38**	**1.71**

Capital Coverage Ratio
Excluding Major Generation
Electric
($ millions)

Fiscal Year Ended	A Consolidated Funds from Operations	B Gas Funds from Operations	C (A-B) **Electric Funds from Operations**	D Consolidated Capital Expenditures	E Gas Capital Expenditures	F (D-E) **Electric Capital Expenditures**	C/F **Electric Capital Coverage**
2010	589	61	**528**	439	25	**414**	**1.28**
2011	595	45	**550**	477	27	**450**	**1.22**
2012	567	49	**518**	503	31	**472**	**1.10**
2013	589	35	**554**	472	34	**438**	**1.26**
2014	690	29	**661**	511	35	**476**	**1.39**
2015			**558**			**571**	**0.98**
2016			**587**			**577**	**1.02**
2017			**571**			**610**	**0.94**
2018			**598**			**547**	**1.09**
2019			**482**			**547**	**0.88**
2020			**441**			**548**	**0.80**
2021			**469**			**573**	**0.82**
2022			**522**			**555**	**0.94**
2023			**613**			**563**	**1.09**
2024			**699**			**571**	**1.22**
2025			**787**			**621**	**1.27**
2026			**818**			**624**	**1.31**
2027			**943**			**637**	**1.48**
2028			**1024**			**649**	**1.58**
2029			**1146**			**675**	**1.70**
2030			**1288**			**665**	**1.94**
2031			**1432**			**703**	**2.04**
2032			**1561**			**711**	**2.20**
2033			**1655**			**724**	**2.29**
2034			**1775**			**735**	**2.41**

Financial Information MFR 8

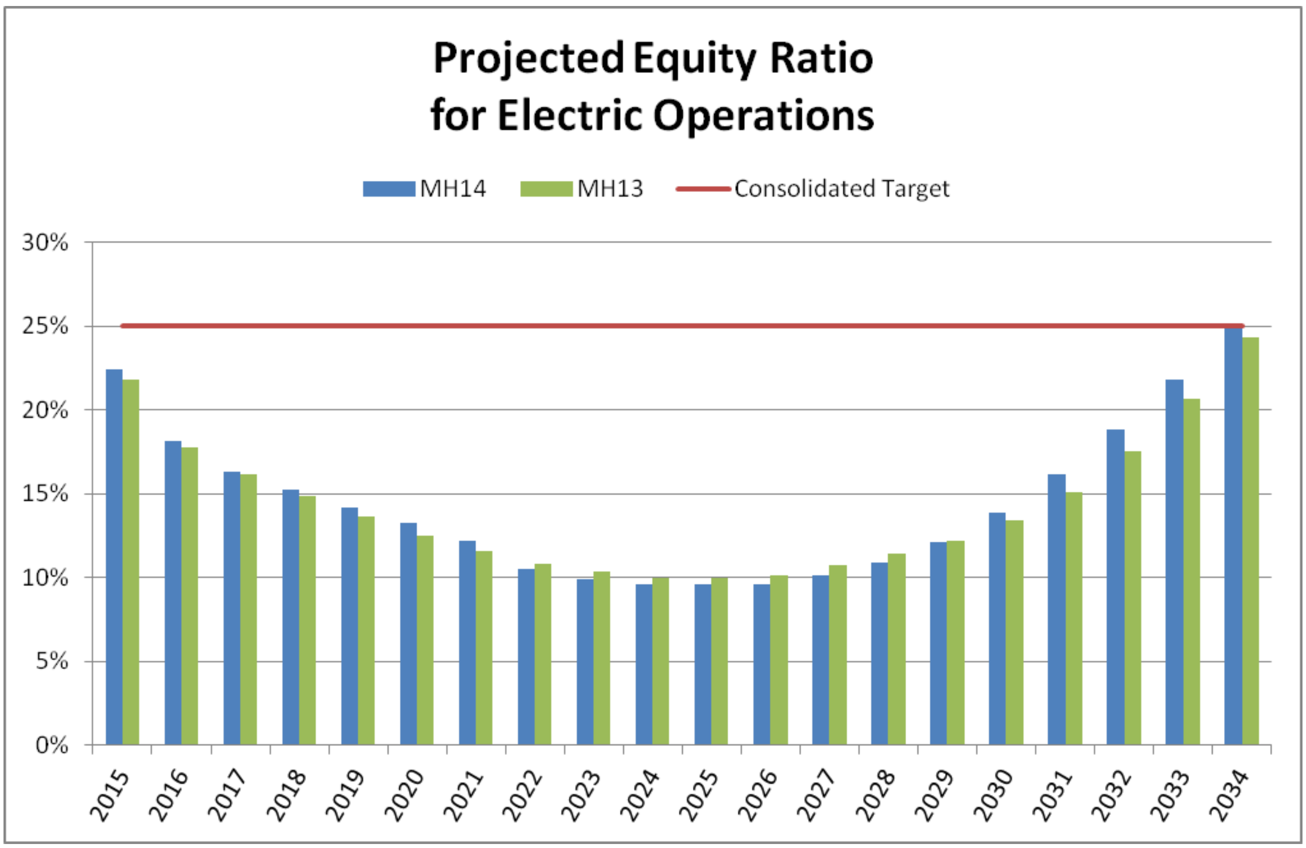
Charts and respective data tables for each of the financial targets similar to PUB/MH I-30 (2012 GRA).

ANSWER:

Equity Ratio

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MH14	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
MH13	22%	18%	16%	15%	14%	12%	12%	11%	10%	10%
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%

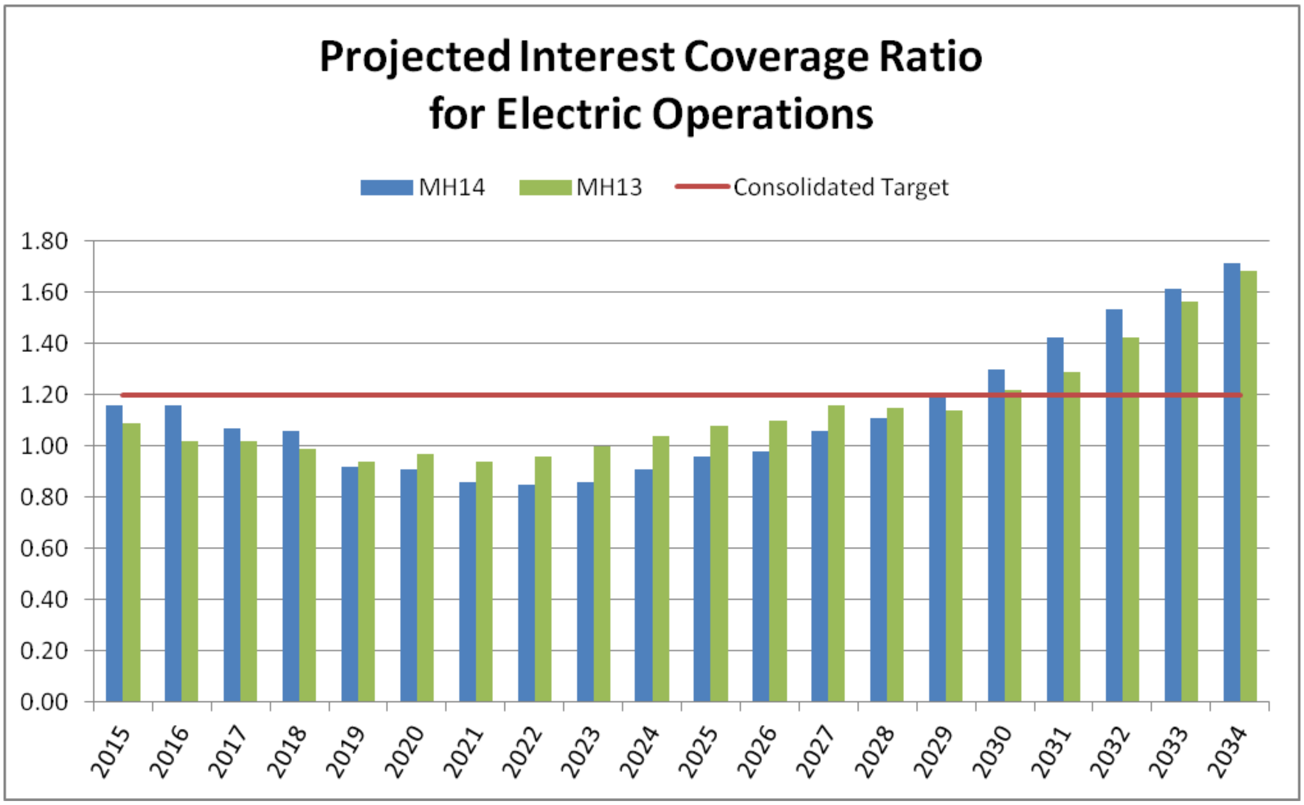
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
MH13	10%	10%	11%	11%	12%	13%	15%	18%	21%	24%
Consolidated Target	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%



Interest Coverage Ratio

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MH14	1.16	1.16	1.07	1.06	0.92	0.91	0.86	0.85	0.86	0.91
MH13	1.09	1.02	1.02	0.99	0.94	0.97	0.94	0.96	1.00	1.04
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

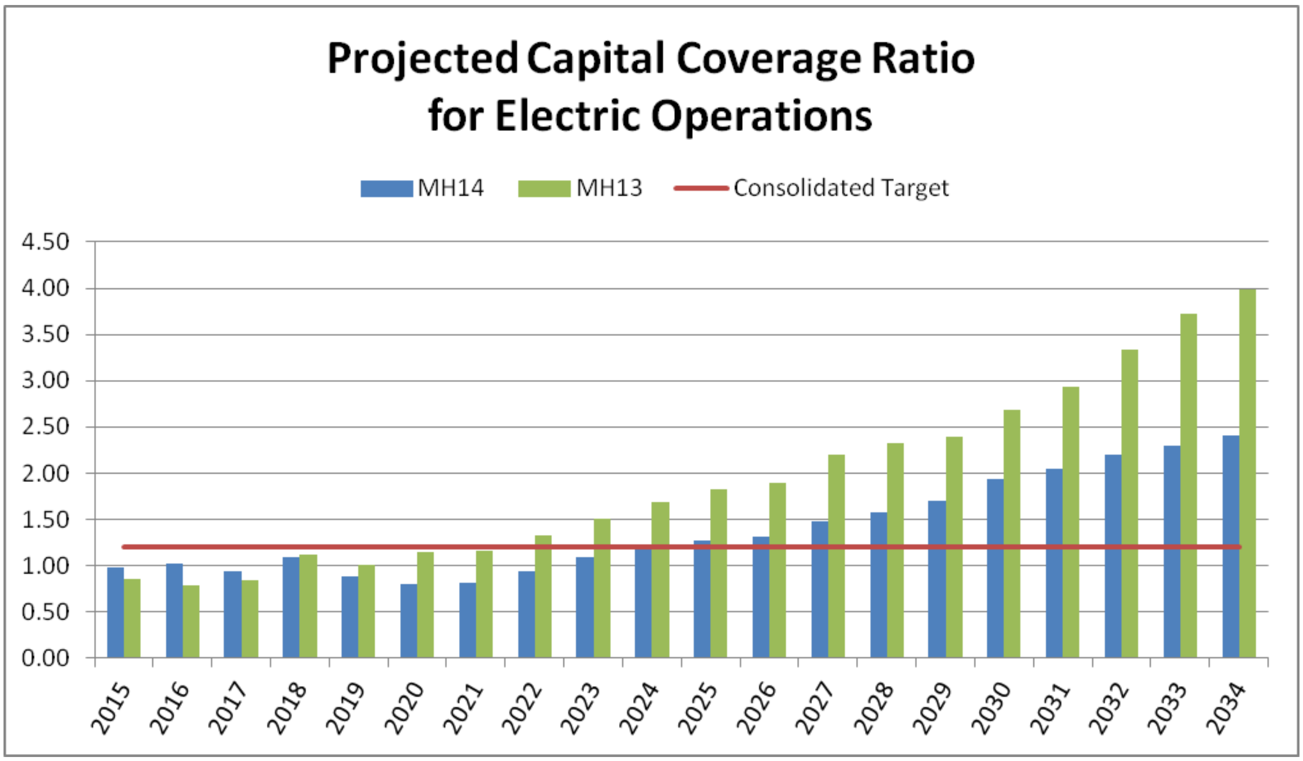
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
MH13	1.08	1.10	1.16	1.15	1.14	1.22	1.29	1.42	1.56	1.68
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



Capital Coverage Ratio

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MH14	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22
MH13	0.86	0.78	0.84	1.12	1.01	1.14	1.16	1.32	1.51	1.68
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MH14	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41
MH13	1.82	1.89	2.20	2.33	2.40	2.68	2.94	3.34	3.72	3.99
Consolidated Target	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20



Financial Information MFR 9

File 20 year 1FF scenarios of revenue requirements/energy depicting post 2003 actual years to date plus future forecast cost components (Finance/ Depreciation/ Operating/ Water Rentals/ F&PP/ Taxes) for:
- 750 MW US Intertie project (CDN & US portions)
- Keeyask generating station
- Bipole Ill and Riel station
- Pointe du Bois spillway & powerhouse
- Wuskwatim overall project
- Base Case (non-major) G+T+D revenue requirement

ANSWER:

Manitoba Hydro understands that in past proceedings, the PUB has expressed an interest in understanding the costs related to Major New Generation and Transmission projects. To assist the PUB's understanding, Manitoba Hydro estimated the carrying and operating costs of forecast Major New Generation and Transmission projects in NFAT Exhibit MH-211. The schedule below has been updated for IFF14 Major New Generation & Transmission, as well as the addition of DSM and Major and Base Capital Expenditures.

However, the most reliable measure of Manitoba Hydro's revenue requirement is the additional General Consumers indicated on the electric operations projected operating statement (Appendix 3.3, pages 37 and 38) which is derived based on balancing the costs of the integrated hydro-electric system, for new asset additions as well as existing assets, with maintaining minimum financial ratios as well as rate stability and affordability for customers.

Costs such as depreciation expense, water rentals, and operating, maintenance and administrative expenses may be directly attributable to a Major New Generation and Transmission asset; however, finance expense, capital taxes and benefits are not. Reliance on the estimated carrying and operating costs in the attached schedule as a representation of revenue requirement must be weighed with the inherent limitations of the analysis, estimation assumptions and methods described below.

1) Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, finance expense attributable to a specific project is estimated for the purposes of this analysis by applying Manitoba Hydro's average cost of debt to the asset's net book value (projected in-service cost net of accumulated depreciation). Using the net book value as the principal outstanding for debt associated with an asset assumes that

annual depreciation expense approximates revenues available to reduce debt over the life of the asset. This estimation method does not consider that extraprovincial revenues partially offset the costs. As a result, the implied impacts to customers for each project may not be representative.

2) Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

3) Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. The assumption that depreciation expense approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the value of a particular asset to the integrated system and should not be used for resource planning purposes.

4) The analysis considers only the prospective costs of asset additions and does not address the ability of revenues at current PUB approved rates to cover ongoing carrying and operating costs of existing assets. Current domestic rates are lower than what they otherwise would have been due to extraprovincial revenues partially offsetting costs. In years of low water flow or low opportunity export prices, domestic revenues are not sufficient to cover the resulting reduction in extraprovincial revenues.

5) The analysis does not consider contributions to reserves in order to maintain Manitoba Hydro’s self-supporting status and affordable, predictable rates for customers.

Thus, the summation of total costs in the attached schedule may not accurately reflect the overall revenue requirement for Manitoba Hydro or how a particular asset contributes to the overall revenue requirement.

If one accepts the estimated carrying and operating costs in the attached schedule with its inherent limitations, cumulative rate increases that would be required to cover the costs of forecast additions in the 10 year forecast period to 2023/24 are up to 75 percentage points higher (117%) compared to the proposed and indicative cumulative rate increases of 42%

over the same time period in MH14. Annual rate increases are between 4% and 20% in the period 2014/15 to 2021/22 with minimal rate adjustments thereafter to 2033/34.

Even if it is assumed that all extraprovincial revenues (net of water rentals and fuel and power purchases) are allocated to offset the prospective costs of additions, the cumulative rate increases that would still be required are up to 37 percentage points higher (79%) compared to the projected 42% cumulative rate increase in MH14 by 2023/24. Annual rate increases are between 4% and 12% in the period 2014/15 to 2021/22 with minimal rate adjustments thereafter.

Whether or not extraprovincial revenues offset the costs, the annual rate increases required in the period to 2021/22 in the attached schedule are considerably higher than the proposed and indicative 3.95% rate increases in MH14. The lower overall revenue requirements in the integrated system analysis shown in additional General Consumers in MH14 compared to this analysis demonstrates that extraprovincial revenues have a key role in offsetting the costs of investments and reducing the compounding effects of the higher carrying costs over time. The annual differences in rate increases compared to MH14's smoothed 3.95% rate increases also show that there is not a direct flow through of costs in each year to customers. Customers benefit directly from Manitoba Hydro's approach in smoothing rate increases while Manitoba Hydro deviates from its financial targets during the capital build-out and then gradually returns to a position of financial strength.

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	80	271	378	371	366	361	355	349	343	338	330	326	305	297	287
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
	8	12	17	23	28	124	395	528	521	517	511	505	498	492	486	479	473	452	443	434

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	1	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	98	95	95	95	93	93	93	91	88	87	86	84	82	81	79	77	75	70	68	66
OM&A Costs	13	12	12	12	12	13	13	13	13	13	14	14	14	14	15	11	11	11	11	11
Depreciation	27	27	27	27	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28
Capital Tax	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	6	6	6	6	6
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	151	147	148	148	146	146	146	144	141	140	139	137	136	134	133	127	125	120	118	116

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	13	23	19	15	132	249	246	241	234	228	222	216	210	204	197	190	185	171	163	156
OM&A Costs	-	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16
Depreciation	7	11	12	12	70	100	100	100	100	100	100	100	100	100	99	99	99	99	99	99
Amortization of BPIII Reserve	-	-	-	-	-	(54)	(54)	(54)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	7	11	17	22	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
	27	46	48	49	234	330	328	323	369	363	357	351	344	338	330	322	317	303	295	287

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	11	22	21	21	20	20	19	18	17	16	16	15	14	13	12	11	10	9
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	19	36	35	34	34	33	32	31	30	30	29	28	27	26	26	24	23	22

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	14	29	32	32	31	31	31	31	30	30	29	29	28	27	27	26	26	24	23	23
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	4	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Capital Tax	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	20	39	42	42	41	41	41	40	40	39	39	38	37	37	36	35	35	33	33	32

DSM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	11	11	13	16	19	21	23	23	23	22	21	20	18	17	17	16	16	15	15	16
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Amortization	32	35	38	41	45	51	55	60	63	65	68	67	66	63	60	55	52	50	49	50
Capital Tax	1	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
	44	49	53	60	66	75	81	86	89	90	91	90	87	83	79	74	71	68	68	69

SUSTAINING CAPITAL
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	17	50	86	120	150	180	215	242	261	286	311	334	362	389	412	433	456	457	472	494
Depreciation	8	25	43	63	81	100	117	134	149	163	179	193	206	222	236	251	264	279	295	309
Capital Tax	5	8	11	13	16	18	20	22	24	26	28	31	33	35	37	39	41	44	46	48
	31	82	140	196	246	298	352	398	434	475	519	558	601	646	686	723	762	780	813	851

Total Incremental Revenue Requirement (without Net Extraprovincial Revenues)	281	375	468	556	800	1 052	1 460	1 668	1 738	1 765	1 793	1 814	1 834	1 858	1 874	1 880	1 904	1 872	1 882	1 897
Annual Rate Increase/(Decrease)	19.56%	5.20%	4.98%	4.11%	11.79%	10.66%	15.82%	6.72%	1.78%	0.42%	0.36%	0.12%	0.12%	0.22%	0.00%	-0.38%	0.12%	-1.46%	-0.32%	-0.15%
Cumulative Rate Increase	19.56%	25.78%	32.04%	37.47%	53.68%	70.05%	96.95%	110.19%	113.93%	114.82%	115.59%	115.85%	116.11%	116.59%	116.59%	115.77%	116.04%	112.88%	112.19%	111.88%
Net Extraprovincial Revenues	(150)	(181)	(147)	(142)	(160)	(195)	(459)	(554)	(569)	(588)	(586)	(521)	(528)	(505)	(496)	(491)	(469)	(449)	(427)	(414)
Total Incremental Revenue Requirement (with Net Extraprovincial Revenues)	131	194	321	413	640	857	1 001	1 114	1 169	1 177	1 208	1 292	1 306	1 353	1 378	1 389	1 435	1 424	1 455	1 483
Annual Rate Increase/(Decrease)	9.10%	3.88%	7.64%	4.82%	11.81%	9.86%	6.00%	4.27%	1.73%	-0.02%	0.72%	2.65%	0.08%	1.20%	0.46%	-0.12%	1.04%	-0.87%	0.49%	0.38%
Cumulative Rate Increase	9.10%	13.34%	22.00%	27.87%	42.97%	57.06%	66.49%	73.61%	76.60%	76.58%	77.85%	82.56%	82.70%	84.90%	85.75%	85.53%	87.45%	85.82%	86.74%	87.46%
IFF14 Annual Rate Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
IFF14 Cumulative Rate Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

Financial Information MFR 10

A schedule detailing General Consumer Revenue for 2005 through the test years detailing rate increases granted in similar format to PUB/MH 1-53 (2012 GRA).

Please see the following table for the requested information.

MANITOBA HYDRO
GENERAL CONSUMERS REVENUE (000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Residential - Base Rates	$ 373 737	$ 360 363	$ 381 532	$ 397 742	$ 405 896	$ 401 304	$ 411 995	$ 390 436	$ 437 224	$ 457 637	$ 433 366	$ 437 595	$ 443 132
General Service - Base Rates	534 958	555 836	570 078	581 124	583 448	563 954	571 525	584 748	604 273	603 547	607 977	614 178	612 878
Base Rates	908 694	916 198	951 610	978 865	989 345	965 258	983 520	975 183	1 041 497	1 061 184	1 041 343	1 051 772	1 056 010
2004/05 Approved Rate Increase (5.0% August 1, 2004)	30 260	45 810	47 580	48 943	49 467	48 263	49 176	48 759	52 075	53 059	52 067	52 589	52 800
2005/06 Approved Rate Increase (2.25% April 1, 2005)	-	21 645	22 482	23 126	23 373	22 804	23 236	23 039	24 605	25 070	24 602	24 848	24 948
2006/07 Approved Rate Increase (2.25% March 1, 2007)	-		1 941	23 646	23 899	23 317	23 758	23 557	25 159	25 635	25 155	25 407	25 510
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	-	-	-	40 728	52 982	53 984	53 527	57 167	58 247	57 158	57 731	57 963
2009/10 Approved Rate Increase (2.9% April 1, 2009)	-	-	-	-	-	32 266	32 877	32 598	34 815	35 473	34 809	35 158	35 300
2010/11 Interim Rate Increase (2.9% April 1, 2010)	-	-	-	-	-	-	33 830	33 543	35 824	36 501	35 819	36 178	36 323
2011/12 Approved Rate Increase (2.0% April 1, 2011)	-	-	-	-	-	-	-	23 804	25 423	25 903	25 419	25 674	25 777
2012/13 Approved Rate Increase (2.0% April 1, 2012	-	-	-	-	-	-	-	-	25 931	26 421	25 927	26 187	26 293
2012/13 Approved Rate Increase (2.4% September 1, 2012)									18 515	32 340	31 735	32 053	32 182
2013/14 Approved Rate Increase (3.5% May 1, 2013)										44 293	47 391	47 866	48 059
2014/15 Approved Rate Increase (2.75% May 1, 2014)											35 316	38 925	39 082
Interim & Approved Rate Increases	30 260	67 455	72 003	95 715	137 468	179 633	216 861	238 827	299 514	362 943	395 400	402 615	404 238
2010/11 (1% rate rollback)	-	-	-	-	-	-	-	(22 894)	-	-	-	-	-
Deferred Revenue from 1% rate rollback	-	-	-	-	-	-	-	(22 894)	-	-	-	-	-
Additional General Consumers Revenue (3.95% April 1, 2015)	-	-	-	-	-	-	-	-	-	-		57 377	57 680
Additional General Consumers Revenue (3.95% April 1, 2016)													59 958
Additional General Consumers Revenue	-	-	-	-	-	-	-	-	-	-	-	57 377	117 638
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	(18 826)	(29 997)	(32 360)	(33 773)
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	(18 826)	(29 997)	(32 360)	(33 773)
Total General Consumer Revenue	$ 938 954	$ 983 653	$ 1 023 613	$ 1 074 580	$ 1 126 812	$ 1 144 891	$ 1 200 381	$ 1 191 117	$ 1 341 011	$ 1 405 301	$ 1 406 745	$ 1 479 405	$ 1 544 112
Rate increase requested	3.00%	2.50%	2.25%	n/a	2.90%	3.90%	2.90%	2.90%	3.50%	3.50%	3.95%	3.95%	3.95%
Rate increase granted	5.00%	2.25%	2.25%	n/a	5.00%	2.90%	1.90%	2.00%	2.0%/2.4%	3.50%	2.75%	n/a	n/a

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE (000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Extraprovincial Revenue	$ 553 727	$ 826 766	$ 592 245	$ 624 971	$ 622 646	$ 426 641	$ 398 306	$ 363 044	$ 352 633	$ 439 182	$ 408 892	$ 434 157	$ 449 738
Water Rentals and Assessments	(135 456)	(124 841)	(226 212)	(134 887)	(176 383)	(103 973)	(106 169)	(145 632)	(133 292)	(125 517)	(124 469)	(122 847)	(112 167)
Fuel and Power Purchased	(111 521)	(131 020)	(112 497)	(123 767)	(123 000)	(121 033)	(120 163)	(119 301)	(117 864)	(177 113)	(134 189)	(130 432)	(190 933)
Net Extraprovincial Revenue	$ 306 750	$ 570 905	$ 253 536	$ 366 316	$ 323 264	$ 201 635	$ 171 974	$ 98 111	$ 101 477	$ 136 552	$ 150 234	$ 180 878	$ 146 637

<u>Financial Information MFR 11</u>

A schedule detailing the statement of Income (Schedule 5.1.0, 2012 GRA) with five years historical through the forecast test years. The schedule should provide two columns for the compound annual growth rate for the historical period and for the forecast period using the final year historical as a starting period. (On a similar basis as PUB/MH 1-52 (a) (2012 GRA)

Please see the following table for the requested information.

MANITOBA HYDRO
STATEMENT OF INCOME

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	Compounded Annual Growth (2008/09 to 2013/14)
Revenue						
General Consumers	1 144 891	1 200 381	1 192 797	1 341 011	1 424 127	5.6
Bipole III Reserve					(18 826)	
Extraprovincial	426 641	398 306	363 044	352 633	439 182	0.7
Other	6 226	6 438	13 848	29 854	21 758	36.7
Total Revenue	$ 1 577 758	$ 1 605 126	$ 1 569 689	$ 1 723 497	$ 1 866 241	4.3
Expenses						
Operating, Maintenance and Administrative	377 551	396 946	412 035	462 952	480 717	6.2
Finance Expense	373 267	388 043	385 044	452 367	435 402	3.9
Depreciation and Amortization	358 179	364 727	353 376	391 923	410 834	3.5
Water Rentals and Assessments	121 033	120 163	119 300	117 864	125 517	0.9
Fuel and Power Purchased	103 973	106 169	145 632	133 292	177 113	14.2
Capital and Other Taxes	75 819	81 322	82 888	86 399	96 750	6.3
Corporate Allocation	8 035	8 892	8 880	9 074	9 074	3.1
Other Expenses	-	-	1 180	4 750	6 294	
Total Expenses	1 417 857	1 466 262	1 508 334	1 658 621	1 741 700	5.3
Non-controlling Interest**	-	-	-	13 160	22 005	
Net Income	$ 159 901	$ 138 863	$ 61 354	$ 78 037	$ 146 545	(2.2)

	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Compounded Annual Growth (2013/14 to 2016/17)
Revenue					
General Consumers*	1 424 127	1 436 742	1 511 765	1 577 885	3.5
Bipole III Reserve	(18 826)	(29 997)	(32 360)	(33 773)	
Extraprovincial	439 182	408 892	434 157	449 738	0.8
Other	21 758	15 223	13 870	13 999	(13.7)
Total Revenue	$ 1 866 241	$ 1 830 860	$ 1 927 432	$ 2 007 849	2.5
Expenses					
Operating, Maintenance and Administrative	480 717	485 755	541 740	551 675	4.7
Finance Expense	435 402	494 852	510 423	547 521	7.9
Depreciation and Amortization	410 834	404 590	400 866	422 404	0.9
Water Rentals and Assessments	125 517	124 469	122 847	112 167	(3.7)
Fuel and Power Purchased	177 113	134 189	130 432	190 933	2.5
Capital and Other Taxes	96 750	99 170	107 156	120 534	7.6
Corporate Allocation	9 074	8 659	8 393	8 396	(2.6)
Other Expenses	6 294	2 311	2 355	2 402	(27.5)
Total Expenses	1 741 700	1 753 995	1 824 211	1 956 032	3.9
Non-controlling Interest**	22 005	25 452	12 126	7 580	
Net Income	$ 146 545	$ 102 317	$ 115 347	$ 59 397	(26.0)

*General Consumers Revenue includes rate increases of 3.95% April 1, 2015 and April 1, 2016

**Non-controlling interest represents NCN’s share of the net income/loss from WPLP.

Financial Information MFR 12

A schedule detailing the actual MH Electric Operations financial statements (i.e. Operating Statement, Balance Sheet and Cash Flow Statement) for last five fiscal years in the same format as the IFF, including the actual electric financial ratios. (PUB/MH 1-51 2012 GRA)

ANSWER:

The financial statements and ratios for 2009/10 through 2013/14 are attached.

Electric Operations
Statement of Income

(millions of dollars)

For the year ended March 31:	2010	2011	2012	2013	2014
Revenues					
General consumers revenue	1 145	1 200	1 193	1 341	1 405
Extraprovincial	427	399	363	352	440
Other	6	6	13	30	22
	1 578	1 605	1 569	1 723	1 867
Cost of Gas sold					
	1 578	1 605	1 569	1 723	1 867
Expenses					
Operating and administrative	378	397	412	463	481
Finance expense	373	388	385	452	435
Depreciation and amortization	358	365	353	392	411
Water rentals and assessments	121	120	119	118	126
Fuel and power purchased	104	106	146	133	177
Capital and other taxes	76	81	83	86	97
Other Expenses	0	0	1	5	6
Corporate allocation	8	9	9	9	9
	1 418	1 466	1 508	1 658	1 742
Net income before non-controlling interest	160	139	61	65	125
Non-controlling interest	0	0	0	13	22
Net Income (Loss)	160	139	61	78	147
Financial Ratios					
Debt Ratio	0.72	0.72	0.74	0.75	0.77
Interest Coverage	1.33	1.26	1.11	1.13	1.25
Capital Coverage	1.28	1.22	1.10	1.26	1.39

Electric Operations
Balance Sheet

(millions of dollars)

As at March 31:	**2010**	**2011**	**2012**	**2013**	**2014**
Assets					
Plant in service	12 088	12 350	12 994	15 132	15 506
Accumulated depreciation	4 402	4 534	4 760	5 020	5 266
Net plant in service	7 686	7 816	8 234	10 112	10 240
Construction in progress	2 051	2 738	3 148	1 965	2 939
Current and other assets	2 011	1 627	1 713	1 743	1 663
Goodwill	108	108	108	108	108
	11 856	12 289	13 203	13 928	14 950
Liabilities and Retained Earnings					
Long-term debt	7 931	8 320	8 866	9 034	10 190
Current and other liabilities	1 109	904	1 209	1 693	1 598
Contributions in aid of construction	263	262	285	307	339
Non-controlling interest	62	87	100	95	73
Share capital	0	0	0	0	0
Retained earnings	2 206	2 349	2 416	2 500	2 654
Accumulated other comprehensive income (loss)	285	367	327	299	96
	11 856	12 289	13 203	13 928	14 950

Electric Operations
Statement of Cash Flows

(millions of dollars)

For the year ended March 31:	2010	2011	2012	2013	2014
Operating Activies					
Cash receipts from customers	1 604	1 626	1 610	1 721	1 880
Cash paid to suppliers and employees	(655)	(705)	(729)	(742)	(799)
Interest paid	(455)	(402)	(398)	(469)	(492)
Interest received	34	31	35	44	72
	528	550	518	554	661
Financing Activities					
Proceeds from long-term debt	1 425	915	698	807	1 320
Sinking fund withdrawals	263	646	23	192	415
Retirement of long-term debt	(452)	(723)	(25)	(302)	(623)
Other	(89)	(158)	35	(71)	(29)
	1 147	680	731	626	1 083
Investing Activities					
Property, plant & equipment, net of contributions	(1 043)	(1 139)	(1 093)	(1 003)	(1 348)
Sinking fund payment	(537)	(119)	(98)	(107)	(197)
Other	(80)	(76)	(78)	(88)	(89)
	(1 660)	(1 334)	(1 269)	(1 198)	(1 634)
Net increase (decrease) in cash	15	(104)	(20)	(18)	110
Cash at beginning of year	159	174	70	50	32
Cash at end of year	174	70	50	32	142

<u>Export & Domestic Revenues MFR 1</u>

File average unit revenue/cost calculation for 20 year IFF13 & IFF14 adding actual results for 2008/09, 2009/10, 2010/11, 2011/12, 2012/13 & 2013/14

Please see the following tables for the requested information.

ACTUAL AVERAGE PRICE CALCULATION

VOLUMES (in GW.h)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Firm Export Sales to Canada	0	0	0	0	0	0
Opportunity Export Sales to Canada	417	373	905	887	760	722
Total Export Sales to Canada	**417**	**373**	**905**	**887**	**760**	**722**
Firm Export Sales to USA	4087	3263	3377	3742	3636	3479
Opportunity Export Sales to USA	5622	7224	6062	5615	4691	6336
Total Export Sales to USA	**9709**	**10487**	**9439**	**9357**	**8327**	**9815**
Purchased Energy	**981**	**1320**	**1154**	**1634**	**1583**	**1823**
REVENUE/COST (in millions of dollars)						
Firm Export Revenues to Canada	0.000	0.000	0.000	0.000	0.000	0.000
Opportunity Export Revenues to Canada	45.389	40.971	35.728	34.416	33.475	20.352
Total Export Revenues to Canada	**45.389**	**40.971**	**35.728**	**34.416**	**33.475**	**20.352**
Firm Export Revenues to USA	233.457	185.966	172.362	174.870	177.049	181.674
Opportunity Export Revenues to USA	236.298	155.346	145.276	117.455	112.744	182.353
Total Export Revenues to USA	**469.755**	**341.312**	**317.638**	**292.325**	**289.793**	**364.027**
Total Export Sales to USA (includes net Trans & Enviro charges)	**491.283**	**324.289**	**296.831**	**270.903**	**265.331**	**339.392**
Total Import Energy	**56.309**	**32.074**	**34.676**	**78.079**	**70.897**	**98.031**
AVERAGE PRICE ($/MW.h))						
Firm Export Sales to Canada	0	0.00	0.00	0.00	0.00	0.00
Opportunity Export Sales to Canada	49.46	33.99	27.76	29.65	36.70	40.11
Total Export Sales to Canada	**49.46**	**33.99**	**27.76**	**29.65**	**36.70**	**40.11**
Firm Export Sales to USA	57.12	56.99	51.09	46.79	48.69	52.22
Opportunity Export Sales to USA	43.24	22.28	24.44	21.13	23.55	27.63
Total Export Sales to USA	**48.83**	**32.95**	**33.71**	**31.23**	**34.48**	**36.46**
Total Export Sales	**48.85**	**32.99**	**33.31**	**31.10**	**34.64**	**36.71**
Import Energy Including Wind	**50.75**	**31.58**	**36.71**	**47.33**	**51.98**	**58.92**

AVERAGE UNIT REVENUE/COST CALCULATION IFF14

FORECAST ->

VOLUMES (in GW.h)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Demand:																				
Manitoba Domestic Energy Sales	22214	22458	22458	22881	23009	23250	23318	23458	23664	23868	24099	24336	24572	24807	25041	25325	25617	25917	26226	26546
Domestic energy Losses	3108	3297	3264	3302	2987	3013	2982	2919	2947	2976	3007	3040	3072	3107	3140	3178	3219	3260	3302	3345
Firm & Opportunity Export Sales to Canada	851	481	860	833	856	870	753	744	602	583	565	489	471	513	502	491	519	513	495	485
Firm & Opportunity Export Sales to US	9184	8596	6444	6192	6143	6289	9464	10232	10207	10017	9789	9462	9410	8960	8780	8559	8200	7870	7501	7258
Net Transmission Losses	958	933	665	632	630	648	927	991	970	949	919	884	877	840	819	793	764	727	692	664
Total Demand Volumes:	**36315**	**35764**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38394**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**
Supply:																				
MH Hydraulic Generation	35116	34418	31084	31129	30907	31456	34535	35275	35251	35253	35138	35078	35243	35141	35144	35146	35224	35125	35133	35157
MH Thermal Generation	101	121	326	349	350	298	151	142	147	140	148	148	155	122	118	120	108	107	106	108
Purchased Energy	1098	1226	2281	2363	2367	2316	2758	2927	2991	3000	3094	2984	3004	2964	3019	3082	2987	3056	2979	3031
Total Supply Volumes:	**36315**	**35764**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38393**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**

REVENUE/COST (in milions of dollars)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Total Manitoba Domestic Energy Sales:																				
Manitoba Domestic Energy Sales @ Approved Rates	1 436.742	1 454.388	1 460.247	1 482.604	1 490.283	1 501.465	1 505.896	1 513.421	1 525.486	1 537.543	1 551.384	1 565.461	1 579.532	1 593.283	1 607.122	1 623.939	1 641.157	1 658.777	1 677.031	1 695.791
Additional Domestic Revenue	0.000	57.448	117.638	182.720	249.787	320.910	394.053	471.445	554.231	641.409	734.027	831.780	934.799	1 043.117	1 157.220	1 279.663	1 409.139	1 485.929	1 565.867	1 648.967
Manitoba Domestic Sales	**1 436.742**	**1 511.836**	**1 577.885**	**1 665.324**	**1 740.070**	**1 822.375**	**1 899.949**	**1 984.866**	**2 079.717**	**2 178.952**	**2 285.411**	**2 397.241**	**2 514.331**	**2 636.400**	**2 764.342**	**2 903.602**	**3 050.296**	**3 144.706**	**3 242.898**	**3 344.758**
Extraprovincial Revenue:																				
Total Export Sales to Canada	28.748	16.104	43.626	43.531	47.304	51.022	46.615	48.502	36.226	37.180	37.246	32.888	32.290	37.764	37.507	37.947	41.842	42.826	42.202	42.644
Total Export Sales to USA	343.003	380.033	379.506	386.312	403.741	435.497	741.684	866.129	892.952	920.218	928.219	864.490	879.933	851.215	849.642	855.646	835.028	823.503	805.418	804.815
Other Non-Energy Related Revenues	19.698	15.880	2.765	2.820	2.876	2.934	2.990	3.046	3.104	3.163	3.223	3.285	3.347	3.411	3.475	3.542	3.609	3.677	3.747	3.818
Transmission Credits	17.443	22.140	23.841	24.294	24.755	24.824	25.296	25.776	26.266	26.765	27.274	27.792	28.320	28.858	29.406	29.965	30.534	31.114	31.706	32.308
Extraprovincial Revenue	**408.892**	**434.157**	**449.738**	**456.958**	**478.677**	**514.277**	**816.584**	**943.454**	**958.548**	**987.327**	**995.962**	**928.454**	**943.890**	**921.247**	**920.031**	**927.099**	**911.013**	**901.120**	**883.073**	**883.586**
Water Rentals & Assessments:																				
MH Water Rentals	117.417	115.049	103.902	104.051	103.310	105.144	115.437	117.912	117.830	117.838	117.451	117.252	117.802	117.462	117.474	117.479	117.738	117.408	117.434	117.516
Assessments	4.934	5.683	6.165	6.329	6.499	6.567	6.742	6.923	7.108	7.300	7.496	7.696	7.903	8.115	8.334	8.558	8.789	9.026	9.269	9.521
Other Costs	2.118	2.115	2.100	2.118	2.137	2.154	2.172	2.190	6.870	7.330	7.595	7.458	7.654	7.858	8.033	8.362	8.715	8.991	9.368	9.765
Water Rentals & Assessments:	**124.469**	**122.847**	**112.167**	**112.499**	**111.946**	**113.866**	**124.351**	**127.024**	**131.808**	**132.467**	**132.541**	**132.407**	**133.359**	**133.435**	**133.841**	**134.399**	**135.243**	**135.425**	**136.071**	**136.802**
Fuel & Power Purchased:																				
MH Thermal Generation	6.179	6.582	19.875	22.437	23.634	21.194	12.914	12.716	13.672	13.493	14.642	15.258	16.653	13.745	13.878	14.658	13.923	14.300	14.763	15.729
Purchased Energy	70.910	73.771	114.268	120.552	123.099	123.490	140.962	153.485	159.405	168.054	176.726	171.822	177.022	179.097	185.295	194.239	194.241	202.792	204.118	214.221
Other Non-Energy related Costs	14.142	12.663	8.777	9.148	9.453	9.568	12.076	29.249	16.313	16.730	17.215	17.686	18.198	18.556	19.048	19.579	20.064	20.610	21.174	21.773
Transmission Charges	42.958	37.416	48.013	50.034	50.985	51.131	67.564	67.344	67.969	68.612	69.275	70.213	70.914	71.636	72.378	73.141	78.423	79.229	80.057	80.908
Fuel & Power Purchased	**134.189**	**130.432**	**190.933**	**202.172**	**207.171**	**205.383**	**233.516**	**262.795**	**257.359**	**266.890**	**277.858**	**274.979**	**282.786**	**283.033**	**290.599**	**301.616**	**306.651**	**316.932**	**320.113**	**332.631**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Manitoba Domestic Energy Sales @ Approved Rates	$ 64.68	$ 64.76	$ 65.02	$ 64.80	$ 64.77	$ 64.58	$ 64.58	$ 64.52	$ 64.47	$ 64.42	$ 64.38	$ 64.33	$ 64.28	$ 64.23	$ 64.18	$ 64.12	$ 64.07	$ 64.00	$ 63.94	$ 63.88
Additional Domestic Revenue	-	2.56	5.24	7.99	10.86	13.80	16.90	20.10	23.42	26.87	30.46	34.18	38.04	42.05	46.21	50.53	55.01	57.33	59.71	62.12
Total Manitoba Domestic Energy Sales @ meter	64.68	67.32	70.26	72.78	75.62	78.38	81.48	84.61	87.89	91.29	94.83	98.51	102.32	106.28	110.39	114.65	119.07	121.34	123.65	126.00
Total Export Sales to Canada	35.86	41.32	56.73	58.67	61.85	65.44	70.39	74.22	70.89	75.53	78.53	82.67	85.02	89.47	91.24	94.72	97.80	101.37	104.39	108.31
Total Export Sales to USA (includes Net Trans Credits)	34.57	42.44	55.14	58.23	61.46	65.06	73.90	80.58	83.40	87.68	90.53	86.88	88.98	90.23	91.87	94.92	96.00	98.52	100.92	104.20
Total Export Sales	34.67	42.39	55.31	58.28	61.50	65.11	73.67	80.20	82.80	87.12	89.98	86.71	88.83	90.19	91.84	94.91	96.09	98.66	101.10	104.41
MH Hydraulic Generation (Water Rentals)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	61.39	54.56	61.03	64.31	67.54	71.04	85.53	89.55	92.72	96.07	99.18	103.09	107.44	112.66	117.70	122.43	129.03	134.10	139.75	145.03
Purchased Energy (Including Assessments)	69.06	64.81	52.79	53.70	54.76	56.15	53.55	54.80	55.67	58.46	59.54	60.15	61.57	63.15	64.14	65.81	67.96	69.31	71.64	73.81

AVERAGE UNIT REVENUE/COST CALCULATION IFF13

VOLUMES (in GW.h)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Demand:																				
Manitoba Domestic Energy Sales	21994	22305	22557	22783	22988	23292	23603	23912	24236	24560	24893	25235	25576	25910	26243	26616	26986	27351	27709	28067
Domestic energy Losses	3198	3237	3122	3140	2831	2874	2901	2900	2929	2994	3045	3115	3184	3222	3342	3381	3448	3489	3544	3595
Firm & Opportunity Export Sales to Canada	690	765	580	586	597	588	583	448	449	444	448	427	435	402	587	780	761	779	771	760
Firm & Opportunity Export Sales to US	9998	8921	6583	6437	6600	6192	6315	9210	9831	9663	9286	8855	8374	9807	12273	12947	12555	12266	12044	11720
Net Transmission Losses	925	913	648	628	640	593	606	868	920	901	861	807	761	926	1206	1277	1233	1210	1183	1147
Total Demand Volumes:	**36806**	**36140**	**33490**	**33574**	**33656**	**33538**	**34007**	**37338**	**38365**	**38561**	**38532**	**38439**	**38330**	**40267**	**43652**	**45001**	**44983**	**45096**	**45251**	**45289**
Supply:																				
MH Hydraulic Generation	35143	34321	30910	30875	30854	30612	31146	34298	35124	35265	35208	34905	34852	37263	40974	42011	41934	42142	42213	42210
MH Thermal Generation	114	132	348	350	357	372	333	230	233	238	229	256	228	249	223	229	229	210	213	210
Purchased Energy	1548	1687	2232	2348	2444	2555	2529	2810	3008	3059	3095	3278	3250	2755	2456	2761	2820	2744	2825	2869
Total Supply Volumes:	**36805**	**36140**	**33490**	**33574**	**33656**	**33538**	**34007**	**37338**	**38365**	**38561**	**38532**	**38439**	**38330**	**40267**	**43652**	**45001**	**44983**	**45096**	**45251**	**45289**

REVENUE/COST (in milions of dollars)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Total Manitoba Domestic Energy Sales:																				
Manitoba Domestic Energy Sales @ Approved Rates	1 396.088	1 407.672	1 423.207	1 438.093	1 452.299	1 470.697	1 489.539	1 508.397	1 527.644	1 547.533	1 567.628	1 588.388	1 609.069	1 629.119	1 649.283	1 671.588	1 693.740	1 715.486	1 736.903	1 758.320
Additional Domestic Revenue	0.000	55.603	114.654	177.234	243.420	314.334	389.773	469.880	555.015	645.577	741.712	843.962	952.279	1 066.579	1 187.578	1 317.211	1 454.288	1 598.904	1 751.418	1 912.502
Manitoba Domestic Sales	**1 396.088**	**1 463.275**	**1 537.861**	**1 615.327**	**1 695.719**	**1 785.031**	**1 879.312**	**1 978.277**	**2 082.659**	**2 193.110**	**2 309.340**	**2 432.350**	**2 561.348**	**2 695.698**	**2 836.861**	**2 988.799**	**3 148.028**	**3 314.390**	**3 488.321**	**3 670.822**
Extraprovincial Revenue:																				
Total Export Sales to Canada	24.182	23.524	19.281	22.107	25.464	27.799	29.371	22.785	24.158	24.914	26.918	26.325	28.023	25.746	40.709	57.274	58.127	62.156	63.938	65.628
Total Export Sales to USA	350.452	329.129	320.587	345.425	392.816	396.894	430.767	712.902	812.871	829.979	828.623	814.539	740.286	923.100	1 168.842	1 258.488	1 254.391	1 249.818	1 264.261	1 263.869
Other Non-Energy Related Revenues	15.587	11.423	2.416	2.461	2.550	2.599	2.648	2.698	2.750	2.802	2.855	2.909	2.965	3.021	3.078	3.137	3.196	3.257	3.319	3.382
Transmission Credits	18.206	18.834	19.290	19.754	20.568	21.000	21.399	21.805	22.220	22.642	23.072	23.510	23.957	24.412	24.876	25.349	25.830	26.321	26.821	27.331
Extraprovincial Revenue	**408.426**	**382.910**	**361.574**	**389.747**	**441.398**	**448.292**	**484.185**	**760.191**	**861.999**	**880.336**	**881.468**	**867.284**	**795.231**	**976.280**	**1 237.506**	**1 344.248**	**1 341.544**	**1 341.552**	**1 358.339**	**1 360.210**
Water Rentals & Assessments:																				
MH Water Rentals	117.480	114.725	103.321	103.204	103.132	102.323	104.108	114.646	117.407	117.875	117.687	116.672	116.496	124.556	136.958	140.427	140.168	140.862	141.100	141.092
Assessments	5.207	5.543	5.721	5.900	6.188	6.365	6.535	6.708	6.886	7.069	7.258	7.451	7.649	7.853	8.063	8.278	8.499	8.727	8.960	9.200
Other Costs	2.213	2.266	2.239	2.258	2.277	2.297	2.317	2.338	2.359	2.380	2.402	2.425	2.447	2.470	2.494	2.518	2.543	2.568	2.593	2.619
Water Rentals & Assessments:	**124.900**	**122.534**	**111.281**	**111.362**	**111.598**	**110.985**	**112.960**	**123.691**	**126.652**	**127.325**	**127.347**	**126.548**	**126.592**	**134.880**	**147.515**	**151.224**	**151.210**	**152.157**	**152.653**	**152.911**
Fuel & Power Purchased:																				
MH Thermal Generation	6.495	8.221	21.990	23.134	25.270	27.652	26.887	21.095	22.250	23.527	23.565	27.130	25.545	28.939	27.230	29.230	30.467	29.450	31.036	31.789
Purchased Energy	81.197	82.788	103.001	110.745	119.348	126.894	129.239	140.533	154.137	161.424	171.888	184.913	183.786	165.823	154.233	172.355	180.289	179.185	189.121	197.346
Other Non-Energy related Costs	11.353	8.768	6.804	7.045	7.304	7.560	7.822	8.951	9.402	9.690	9.987	10.294	10.610	10.937	11.273	11.620	11.978	12.347	12.728	13.121
Transmission Charges	45.311	42.530	41.717	47.648	50.630	51.692	52.674	79.572	78.916	78.419	78.065	77.843	77.741	77.726	77.768	77.866	78.020	78.230	78.495	78.814
Fuel & Power Purchased	**144.355**	**142.306**	**173.511**	**188.572**	**202.552**	**213.798**	**216.622**	**250.151**	**264.704**	**273.060**	**283.506**	**300.180**	**297.682**	**283.425**	**270.504**	**291.071**	**300.754**	**299.212**	**311.379**	**321.069**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Manitoba Domestic Energy Sales @ Approved Rates	$ 63.48	$ 63.11	$ 63.09	$ 63.12	$ 63.18	$ 63.14	$ 63.11	$ 63.08	$ 63.03	$ 63.01	$ 62.98	$ 62.94	$ 62.91	$ 62.88	$ 62.85	$ 62.80	$ 62.76	$ 62.72	$ 62.68	$ 62.65
Additional Domestic Revenue	-	2.49	5.08	7.78	10.59	13.50	16.51	19.65	22.90	26.29	29.80	33.44	37.23	41.16	45.25	49.49	53.89	58.46	63.21	68.14
Total Manitoba Domestic Energy Sales @ meter	63.48	65.60	68.18	70.90	73.77	76.64	79.62	82.73	85.93	89.30	92.77	96.39	100.15	104.04	108.10	112.29	116.65	121.18	125.89	130.79
Total Export Sales to Canada	35.87	34.97	39.38	44.63	50.28	55.95	59.63	63.79	67.41	70.47	75.44	78.24	81.51	82.83	82.00	83.12	86.75	90.38	94.03	98.08
Total Export Sales to USA (includes Net Trans Credits)	32.34	34.24	45.29	49.33	54.97	59.14	63.26	71.13	76.92	80.12	83.31	85.85	81.98	88.69	90.92	93.15	95.76	97.66	100.68	103.45
Total Export Sales	32.56	34.29	44.88	49.00	54.63	58.91	63.00	70.86	76.59	79.78	83.02	85.58	81.97	88.51	90.58	92.64	95.30	97.27	100.32	103.16
MH Hydraulic Generation (Water Rentals)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	56.84	62.18	63.19	66.13	70.71	74.37	80.85	91.64	95.49	99.00	102.86	105.98	112.22	116.31	122.26	127.54	132.83	139.93	145.46	151.44
Purchased Energy (Including Assessments)	55.83	52.36	48.71	49.67	51.35	52.16	53.69	52.40	53.53	55.08	57.88	58.68	58.90	63.03	66.09	65.43	66.95	68.49	70.11	72.00

Export and Domestic Revenue MFR 3 (Revised)

Re-file Dec 2013 Revised PUB/MH 1-009 (NFAT) updated to end of 2014

- **Monthly NEB data on firm/interruptible by export permit number plus imports**
- **Separately summarizes summer and winter components for each year**

Please see the tables below.

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Apr-08	144	17,554	1,331,013	7.6						
	155	21,063	1,081,235	5.1						
	224	175,438	9,140,552	5.2						
	259	523	33,718	6.4						
	269				674,057	38,710,758	5.7			
								498	56,930	11.4
May-08	35	81,724	3,401,427	4.2						
	144	17,600	1,282,846	7.3						
	155	21,120	1,087,816	5.2						
	224	175,500	9,220,917	5.3						
	259	396	28,906	7.3						
	269				699,599	31,370,396	4.5			
								500	47,713	9.5
Jun-08	33	19,490	697,220	3.6						
	34	14,617	522,897	3.6						
	35	73,902	3,379,308	4.6						
	144	16,407	1,233,972	7.5						
	155	19,866	1,068,185	5.4						
	224	162,001	8,977,792	5.5						
	259	475	31,630	6.7						
	269				494,860	24,520,507	5.0			
								4,897	744,598	15.2
Jul-08	33	70,400	2,535,990	3.6						
	34	52,800	1,901,992	3.6						
	35	96,900	5,633,561	5.8						
	144	18,380	1,375,994	7.5						
	155	22,055	1,157,066	5.2						
	224	183,686	9,799,722	5.3						
	259	366	28,736	7.9						
	269				799,886	37,260,178	4.7			
								1,106	134,304	12.1
Aug-08	33	67,200	2,507,804	3.7						
	34	50,400	1,880,853	3.7						
	35	108,900	4,898,303	4.5						
	144	16,788	1,314,433	7.8						
	155	20,160	1,125,657	5.6						
	224	168,000	9,583,228	5.7						
	259	383	29,647	7.7						
	269				859,734	34,817,392	4.0			
								2,356	254,097	10.8

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Sep-08	33	19,210	705,067	3.7						
	34	14,407	536,282	3.7						
	35	106,950	3,584,400	3.4						
	144	17,428	1,354,954	7.8						
	155	21,120	1,159,702	5.5						
	224	173,640	9,762,961	5.6						
	259	357	28,666	8.0						
	269				795,097	23,433,570	2.9			
								492	52,767	10.7
Oct-08	35	111,600	4,153,724	3.7						
	144	18,400	1,633,552	8.9						
	155	22,080	1,373,405	6.2						
	224	184,000	11,635,701	6.3						
	259	384	29,688	7.7						
	269				694,487	24,144,820	3.5			
								1,199	82,222	6.9
Nov-08	144	15,994	1,465,977	9.2						
	155	19,200	1,265,540	6.6						
	224	160,000	10,819,982	6.8						
	259	642	39,378	6.1						
	269				614,926	24,241,549	3.9			
								300	8,925	3.0
Dec-08	144	18,381	1,642,812	8.9						
	155	22,080	1,382,550	6.3						
	224	158,320	10,639,551	6.7						
	259	854	52,411	6.1						
	269				197,415	13,641,499	6.9			
								48,883	1,682,653	3.4
Jan-09	144	17,600	1,595,364	9.1						
	155	21,117	1,352,687	6.4						
	224	161,779	10,888,078	6.7						
	259	1,192	68,796	5.8						
	269				123,830	7,442,112	6.0			
								61,915	2,559,045	4.1
Feb-09	144	16,000	1,506,201	9.4						
	155	19,200	1,301,862	6.8						
	224	156,110	10,944,203	7.0						
	259	833	50,946	6.1						
	269				173,600	8,571,553	4.9			
								6,749	344,517	5.1
Mar-09	144	17,568	1,623,272	9.2						
	155	21,120	1,378,863	6.5						
	224	172,308	11,550,659	6.7						
	259	833	50,946	6.1						
	269				194,748	8,194,807	4.2			
								19,095	719,180	3.8

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Apr-09	144	17,541	1,536,031	8.8						
	155	21,049	1,303,354	6.2						
	224	175,418	11,070,661	6.3						
	259	639	40,227	6.3						
	269				466,954	11,164,381	2.4			
								500	61,317	12.3
May-09	33	47,217	629,505	1.3						
	34	35,430	469,493	1.3						
	35	52,174	1,046,940	2.0						
	144	16,588	1,445,711	8.7						
	155	9,928	587,038	5.9						
	224	287,476	11,604,608	4.0						
	259	481	35,977	7.5						
	269				448,634	10,411,481	2.3			
								813	33,550	4.1
Jun-09	33	86,711	2,357,030	2.7						
	34	6,588	1,805,106	27.4						
	35	7,200	308,462	4.3						
	144	17,600	1,617,138	9.2						
	155	16,078	758,261	4.7						
	224	303,767	13,019,826	4.3						
	259	461	35,204	7.6						
	269				434,693	11,286,387	2.6			
								1,851	32,292	1.7
Jul-09	33	119,319	2,928,700	2.5						
	34	89,632	2,197,587	2.5						
	35	2,250	58,679	2.6						
	144	18,400	1,562,504	8.5						
	155	14,731	680,137	4.6						
	224	358,969	12,602,626	3.5						
	259	394	32,545	8.3						
	269				521,232	10,303,089	2.0			
								1,851	160,870	8.7
Aug-09	33	132,126	3,214,448	2.4						
	34	9,063	2,410,700	26.6						
	35	1,650	43,737	2.7						
	144	16,800	1,463,074	8.7						
	155	13,800	653,061	4.7						
	224	362,391	12,705,102	3.5						
	259	425	33,766	7.9						
	269				512,427	11,298,361	2.2			
								495	34,035	6.9
Sep-09	33	28,367	961,127	3.4						
	34	21,352	724,358	3.4						
	144	16,888	1,437,114	8.5						
	155	15,644	682,116	4.4						
	224	176,859	9,980,692	5.6						
	259	320	29,621	9.3						
	269				721,192	13,904,731	1.9			
								437	41,672	9.5

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Oct-09	35	77,706	2,358,613	3.0						
	144	17,358	1,480,174	8.5						
	155	10,416	596,508	5.7						
	224	173,876	10,162,359	5.8						
	269				866,924	20,512,094	2.4			
	345	527	37,820	7.2						
								0	0	0.0
Nov-09	144	16,800	1,410,645	8.4						
	155	10,080	572,268	5.7						
	224	168,000	9,756,683	5.8						
	269				652,817	15,208,111	2.3			
	345	503	36,853	7.3						
								12,766	291,376	2.3
Dec-09	144	18,337	1,510,887	8.2						
	155	11,002	602,185	5.5						
	224	178,620	10,045,274	5.6						
	269				180,369	7,233,228	4.0			
	345	785	50,708	6.5						
								96,983	2,446,474	2.5
Jan-10	144	16,800	1,420,784	8.5						
	155	10,080	576,381	5.7						
	224	157,869	9,449,930	6.0						
	269				294,690	12,031,863	4.1			
	345	1,004	61,779	6.2						
								78,020	1,928,233	2.5
Feb-10	144	1,600	1,344,224	84.0						
	155	9,600	550,946	5.7						
	224	159,086	9,384,649	5.9						
	269				238,998	9,492,286	4.0			
	345	948	58,242	6.1						
								43,325	1,060,605	2.4
Mar-10	144	18,389	1,469,898	8.0						
	155	11,033	585,515	5.3						
	224	183,900	9,935,043	5.4						
	269				496,047	14,153,374	2.9			
	345	684	46,670	6.8						
								1,107	15,147	1.4
Apr-10	144	17,111	1,371,751	8.0						
	155	10,308	556,029	5.4						
	224	171,379	9,453,481	5.5						
	269				502,793	11,922,854	2.4			
	345	455	34,287	7.5						
								1,175	19,334	1.6
May-10	35	53,700	1,874,870	3.5						
	155	10,080	573,486	5.7						
	224	167,000	9,737,141	5.8						
	269				194,547	7,894,406	4.1			
	345	357	25,898	7.3						
								122,179	2,634,286	2.2

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jun-10	33	37,900	1,460,750	3.9						
	34	28,495	1,098,260	3.9						
	35	82,651	2,570,108	3.1						
	155	10,560	599,904	5.7						
	224	171,412	10,026,035	5.8						
	269				461,086	13,150,740	2.9			
	273	4	515	12.9						
	345	356	25,910	7.3						
								5,241	60,258	1.1
Jul-10	33	56,900	2,127,711	3.7						
	34	42,672	1,595,671	3.7						
	35	106,253	3,410,437	3.2						
	155	10,511	580,139	5.5						
	224	175,324	9,869,728	5.6						
	269				738,392	19,473,860	2.6			
	345	424	28,688	6.8						
								3,755	218,864	5.8
Aug-10	33	55,590	2,149,228	3.9						
	34	41,765	1,614,724	3.9						
	35	110,249	3,928,184	3.6						
	155	10,403	595,507	5.7						
	224	173,783	10,146,551	5.8						
	269				748,854	22,321,983	3.0			
	345	374	25,689	6.9						
								1,660	56,302	3.4
Sep-10	33	25,000	935,573	3.7						
	34	18,600	696,067	3.7						
	35	97,125	2,254,630	2.3						
	155	21,600	801,336	3.7						
	224	175,000	9,865,613	5.6						
	269				656,585	13,486,571	2.1			
	345	395	28,650	7.3						
								1,654	56,879	3.4
Oct-10	33	639	23,658	3.7						
	34	484	17,919	3.7						
	35	107,046	2,616,994	2.4						
	155	10,069	557,502	5.5						
	224	167,819	9,501,757	5.7						
	269				788,954	18,110,622	2.3			
	345	389	27,656	7.1						
								2,192	100,023	4.6
Nov-10	33									
	34									
	35									
	155	10,560	580,559	5.5						
	224	167,297	9,553,709	5.7						
	269									
	345	545	37,269	6.8						
	355				547,247	12,127,472	2.2			
								10,623	554,475	5.2

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Dec-10	155	11,040	580,475	5.3						
	224	153,546	8,774,516	5.7						
	345	786	51,282	6.5						
	355				303,045	8,939,053	2.9			
								25,018	682,532	2.7
Jan-11	155	10,080	548,832	5.4						
	224	112,447	7,386,342	6.6						
	345	1,191	71,423	6.0						
	352	8	915	11.4						
	355				245,554	7,812,197	3.2			
								24,152	721,794	3.0
Feb-11	155	9,596	515,658	5.4						
	224	121,398	7,485,752	6.2						
	345	936	60,466	6.5						
	355				330,931	7,867,230	2.4			
								7,413	203,037	2.7
Mar-11	155	11,032	566,877	5.1						
	224	167,830	9,063,793	5.4						
	345	858	57,603	6.7						
	355				502,988	11,600,765	2.3			
								6,029	189,946	3.2
Apr-11	155	15,572	606,291	3.9						
	224	164,230	8,726,760	5.3						
	345	579	39,945	6.9						
	355				618,224	14,188,453	2.3			
								3,256	109,433	3.4
May-11	35	42,777	792,209	1.9						
	155	16,324	648,972	4.0						
	224	173,679	9,311,462	5.4						
	345	368	28,018	7.6						
	355				797,049	15,842,119	2.0			
								5,182	(1,351)	0.0
Jun-11	33	41,459	1,464,428	3.5						
	34	31,095	1,098,347	3.5						
	35	107,501	2,191,176	2.0						
	155	15,915	636,843	4.0						
	224	174,716	9,303,831	5.3						
	345	363	26,742	7.4						
	352	4	598	15.0						
	355				646,648	12,969,331	2.0			
								8,705	393,106	4.5
Jul-11	33	50,289	1,756,982	3.5						
	34	37,717	1,317,745	3.5						
	35	111,478	3,815,718	3.4						
	155	10,055	528,715	5.3						
	224	164,093	8,878,007	5.4						
	345	429	29,265	6.8						
	355				875,740	24,180,464	2.8			
								639	71,427	11.2

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Aug-11	33	51,800	1,856,449	3.6						
	34	38,850	1,392,337	3.6						
	35	110,100	3,291,117	3.0						
	155	11,040	576,490	5.2						
	224	180,211	9,631,375	5.3						
	345	362	25,789	7.1						
	355				793,003	19,359,907	2.4			
								1,264	132,285	10.5
Sep-11	33	30,775	1,171,140	3.8						
	34	23,090	878,688	3.8						
	35	98,726	2,285,351	2.3						
	155	15,629	675,726	4.3						
	224	164,376	9,640,954	5.9						
	345	383	27,659	7.2						
	355				486,600	10,262,974	2.1			
								9,098	199,844	2.2
Oct-11	35	108,181	2,373,741	2.2						
	155	13,777	603,480	4.4						
	224	166,825	9,306,310	5.6						
	345	347	28,276	8.1						
	355				510,915	9,244,684	1.8			
								3,209	77,832	2.4
Nov-11	35	91,504	2,321,519	2.5						
	155	10,417	585,995	5.6						
	224	163,189	9,575,319	5.9						
	345	494	35,603	7.2						
	355				298,541	7,194,432	2.4			
								23,347	491,168	2.1
Dec-11	35	73,016	2,086,927	2.9						
	155	10,560	580,752	5.5						
	224	119,976	7,829,309	6.5						
	345	684	46,526	6.8						
	352	6	813	13.6						
	355				159,283	4,441,916	2.8			
								45,055	1,041,320	2.3
Jan-12	35	70,101	1,685,321	2.4						
	155	10,560	574,013	5.4						
	224	112,150	7,458,255	6.7						
	345	966	62,509	6.5						
	355				178,927	4,636,174	2.6			
								45,241	716,312	1.6
Feb-12	35	68,150	1,666,184	2.4						
	155	10,080	545,463	5.4						
	224	147,786	8,572,594	5.8						
	345	826	55,996	6.8						
	355				93,295	3,015,205	3.2			
								95,568	1,766,968	1.8

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Mar-12	35	68,747	1,455,483	2.1						
	155	10,514	568,790	5.4						
	224	172,839	9,572,792	5.5						
	345	651	45,895	7.0						
	355				230,778	5,366,606	2.3			
								75,530	1,022,020	1.4
Apr-12	35	55,841	1,221,903	2.2						
	155	9,315	517,831	5.6						
	224	156,012	8,877,846	5.7						
	345	453	32,264	7.1						
	355				236,123	5,873,395	2.5			
								52,158	531,110	1.0
May-12	35	76,063	2,221,192	2.9						
	224	184,000	10,579,446	5.7						
	345	341	27,081	7.9						
	355				464,857	13,582,975	2.9			
								31,231	768,543	2.5
Jun-12	33	40,012	1,529,924	3.8						
	34	30,006	1,147,328	3.8						
	35	86,734	2,207,808	2.5						
	224	165,407	9,726,511	5.9						
	345	376	28,743	7.6						
	352	4	603	15.1						
	355				535,127	11,377,035	2.1			
								25,972	593,308	2.3
Jul-12	33	52,764	1,982,477	3.8						
	34	39,572	1,486,820	3.8						
	35	105,142	3,420,647	3.3						
	224	171,959	9,802,259	5.7						
	345	455	31,292	6.9						
	355				837,601	21,851,425	2.6			
								1,076	155,753	14.5
Aug-12	33	54,842	2,029,482	3.7						
	34	41,127	1,521,945	3.7						
	35	110,079	2,538,456	2.3						
	224	182,292	10,030,869	5.5						
	345	356	25,882	7.3						
	355				861,775	16,724,262	1.9			
								965	131,401	13.6
Sep-12	33	25,700	948,547	3.7						
	34	19,276	711,447	3.7						
	35	106,275	2,112,887	2.0						
	224	159,207	9,166,095	5.8						
	345	373	28,105	7.5						
	355				721,490	13,980,585	1.9			
								1,054	5,994	0.6

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Oct-12	35	83,081	2,206,126	2.7						
	224	182,081	10,148,590	5.6						
	345	440	38,755	8.8						
	355				344,967	10,007,508	2.9			
								14,646	152,582	1.0
Nov-12	35	67,050	1,927,256	2.9						
	224	159,745	9,274,114	5.8						
	345	576	39,686	6.9						
	355				225,082	6,652,755	3.0			
								37,599	843,016	2.2
Dec-12	35	61,875	2,123,564	3.4						
	224	129,155	8,179,452	6.3						
	345	729	51,157	7.0						
	352	11	1,300	11.8						
	355				84,723	3,604,653	4.3			
								132,654	3,112,020	2.3
Jan-13	35	66,150	2,181,518	3.3						
	224	169,751	9,694,967	5.7						
	345	1,172	76,021	6.5						
	355				86,194	3,545,803	4.1			
								121,703	3,513,341	2.9
Feb-13	35	66,150	2,076,848	3.1						
	224	155,269	9,453,748	6.1						
	345	1,157	75,852	6.6						
	355				153,549	5,156,723	3.4			
								55,965	1,849,321	3.3
Mar-13	35	86,700	2,820,083	3.3						
	224	168,000	9,789,201	5.8						
	345	771	55,660	7.2						
	355				352,598	11,406,112	3.2			
								10,005	374,131	3.7
Apr-13	35	103,820	3,357,126	3.2						
	224	171,343	9,831,099	5.7						
	345	672	47,102	7.0						
	355				354,939	11,822,526	3.3			
								17,123	495,957	2.9
May-13	35	111,440	3,163,407	2.8						
	224	183,788	10,749,558	5.8						
	345	341	27,081	7.9						
	355				464,857	13,582,975	2.9			
								2,505	87,170	3.5
Jun-13	33	32,938	1,322,307	4.0						
	34	24,702	991,670	4.0						
	35	107,636	2,945,708	2.7						
	224	158,794	9,953,623	6.3						
	345	414	31,011	7.5						
	352	9	1,175	13.1						
	355				852,421	20,994,789	2.5			
								1,686	91,559	5.4

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jul-13	33	60,366	2,371,542	3.9						
	34	45,275	1,778,676	3.9						
	35	111,334	3,463,052	3.1						
	224	183,917	10,700,422	5.8						
	345	434	32,283	7.4						
	355				955,531	25,629,741	2.7			
								2,474	186,819	7.6
Aug-13	33	54,620	2,201,290	4.0						
	34	41,003	1,652,499	4.0						
	35	111,495	3,339,358	3.0						
	224	174,750	10,617,822	6.1						
	345	376	28,247	7.5						
	379	80,023	2,216,928	2.8						
	355				902,359	22,540,778	2.5			
								2,469	433,454	17.6
Sep-13	33	20,789	816,559	3.9						
	34	15,585	612,154	3.9						
	35	80,035	2,134,183	2.7						
	224	130,146	8,644,370	6.6						
	345	376	30,511	8.1						
	379	57,526	1,435,549	2.5						
	355				651,033	15,711,517	2.4			
								2,679	104,702	3.9
Oct-13	35	106,105	3,045,103	2.9						
	224	183,718	10,840,420	5.9						
	345	415	32,481	7.8						
	379	53,097	1,701,338	3.2						
	355				752,750	19,523,112	2.6			
								738	24,482	3.3
Nov-13	35	83,290	2,287,598	2.7						
	224	153,190	9,815,402	6.4						
	345	696	49,473	7.1						
	379	25,132	796,919	3.2						
	355				310,592	8,792,251	2.8			
								21,725	539,951	2.5
Dec-13	35	52,414	2,191,693	4.2						
	224	136,243	9,517,567	7.0						
	345	893	64,070	7.2						
	352	16	1,926	12.0						
	355				89,619	4,554,245	5.1			
								73,075	2,707,912	3.7
Jan-14	35	20,400	883,602	4.3						
	224	179,829	11,397,041	6.3						
	345	1,339	88,923	6.6						
	355				90,736	7,153,983	7.9			
								176,865	8,488,522	4.8
Feb-14	35	4,500	250,082	5.6						
	224	158,243	10,464,053	6.6						
	355				105,955	7,341,754	6.9			
								143,638	6,065,761	4.2

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Mar-14	35	44,100	1,594,046	3.6						
	224	166,631	10,791,002	6.5						
	355				269,824	11,669,319	4.3			
								70,686	2,883,423	4.1
Apr-14	35	93,413	2,858,196	3.1						
	224	171,075	10,874,752	6.4						
	345	646	50,353	7.8						
	355				425,204	13,256,983	3.1			
								15,591	704,819	4.5
May-14	35	62,597	2,133,036	3.4						
	224	153,376	10,113,960	6.6						
	345	492	36,654	7.5						
	355				500,883	14,512,390	2.9			
	379	56,897	1,596,704	2.8						
								1,039	96,058	9.2
Jun-14	33	34,004	1,392,207	4.1						
	34	25,503	1,044,156	4.1						
	35	104,869	3,049,172	2.9						
	224	166,910	10,475,140	6.3						
	345	393	31,252	8.0						
	352	15	1,789	11.9						
	355				744,637	18,443,973	2.5			
	379	74,512	1,889,520	2.5						
								1,724	157,335	9.1
Jul-14	33	54,236	2,265,066	4.2						
	34	40,693	1,699,468	4.2						
	35	109,930	3,097,594	2.8						
	224	177,986	11,135,017	6.3						
	345	411	32,095	7.8						
	355				805,822	20,458,853	2.5			
	379	76,895	2,050,328	2.7						
								2,682	99,522	3.7
Aug-14	33	53,572	2,230,761	4.2						
	34	40,179	1,673,071	4.2						
	35	111,535	3,459,257	3.1						
	224	167,840	10,691,381	6.4						
	345	446	33,090	7.4						
	355				842,745	23,057,388	2.7			
	379	77,556	2,244,478	2.9						
								4,954	294,238	5.9
Sep-14	33	28,101	1,207,856	4.3						
	34	21,070	905,645	4.3						
	35	101,590	2,599,528	2.6						
	224	162,724	10,822,131	6.7						
	345	362	29,507	8.2						
	355				574,335	12,918,717	2.2			
	379	69,976	1,550,750	2.2						
								1,302	54,496	4.2

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Oct-14	35	39,011	937,722	2.4						
	224	135,671	9,749,090	7.2						
	345									
	355				159,474	4,219,443	2.6			
	393	453	31,108	6.9						
								426	8,820	2.1
Nov-14	224	159,835	10,910,455	6.8						
	355				386,148	12,020,955	3.1			
	393	683	51,383	7.5						
								61,354	1,580,745	2.6
Dec-14	224	183,763	12,111,995	6.6						
	352	19	2,262	11.9						
	355				323,436	10,594,264	3.3			
	393	828	61,108	7.4						
								29,342	1,174,253	4.0

Table below is broken into Winter and Summer Season. Summer is considered to include the months of May to October. Winter includes April and November to March.

		FIRM			INTERRUPTIBLE			IMPORT		
Season	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
2008/09										
Winter	144	103,097	9,164,639	8.9						
	155	123,780	7,762,737	6.3						
	224	983,955	63,983,025	6.5						
	259	4,877	296,195	6.1						
	269				1,978,576	100,802,278	5.1			
								137,440	5,371,250	3.9
2008/09	33	176,300	6,446,081	3.7						
Summer	34	132,224	4,842,024	3.7						
	35	579,976	25,050,723	4.3						
	144	105,003	8,195,751	7.8						
	155	126,401	6,971,831	5.5						
	224	1,046,827	58,980,321	5.6						
	259	2,361	177,273	7.5						
	269				4,343,663	175,546,863	4.0			
								10,550	1,315,701	12.5
2009/10										
Winter	144	89,467	8,692,469	9.7						
	155	72,844	4,190,649	5.8						
	224	1,022,893	59,642,240	5.8						
	259	639	40,227	6.3						
	269				2,329,875	69,283,243	3.0			
	345	3,924	254,252	6.5						
								232,701	5,803,152	2.5
2009/10	33	413,740	10,090,810	2.4						
Summer	34	162,065	7,607,244	4.7						
	35	157,868	5,253,545	3.3						
	144	102,390	8,250,717	8.1						
	155	241,812	13,255,697	5.5						
	224	1,486,799	60,124,142	4.0						
	259	1,761	137,492	7.8						
	269				3,505,102	77,716,143	2.2			
	345	527	37,820	7.2						
								5,447	302,419	5.6
2010/11										
Winter	144	17,111	1,371,751	8.0						
	155	62,616	3,348,430	5.3						
	224	893,897	51,717,593	5.8						
	269				502,793	11,922,854	2.4			
	345	4,771	312,330	6.5						
	352	8	915	11.4						
	355				1,929,765	48,346,717	2.5			
								74,410	2,371,118	3.2
2010/11	33	176,029	6,696,920	3.8						
Summer	34	132,016	5,022,641	3.8						
	35	557,024	16,655,223	3.0						
	155	73,223	3,707,874	5.1						
	224	1,030,338	59,146,825	5.7						
	269				3,588,418	94,438,182	2.6			
	273	4	515	12.9						
	345	2,295	162,491	7.1						
								136,681	3,126,612	2.3

		FIRM			INTERRUPTIBLE			IMPORT		
Season	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
2011/12										
Winter	35	371,518	9,215,434	2.5						
	155	67,703	3,461,304	5.1						
	224	880,170	51,735,029	5.9						
	345	4,200	286,474	6.8						
	352	6	813	13.6						
	355				1,579,048	38,842,786	2.5			
								287,997	5,147,221	1.8
2011/12	33	174,323	6,248,999	3.6						
Summer	34	130,752	4,687,117	3.6						
	35	578,763	14,749,312	2.5						
	155	82,740	3,670,226	4.4						
	224	1,023,900	56,071,939	5.5						
	345	2,252	165,749	7.4						
	352	4	598	15.0						
	355				4,109,955	91,859,479	2.2			
								28,097	873,143	3.1
2012/13										
Winter	35	403,766	12,351,172	3.1						
	155	9,315	517,831	5.6						
	224	937,932	55,269,328	5.9						
	345	4,858	330,640	6.8						
	352	11	1,300	11.8						
	355				1,138,269	36,239,441	3.2			
								410,084	10,222,939	2.5
2012/13	33	173,318	6,490,430	3.7						
Summer	34	129,981	4,867,540	3.7						
	35	567,374	14,707,116	2.6						
	224	1,044,946	59,453,770	5.7						
	345	2,341	179,858	7.7						
	352	4	603	15.1						
	355				3,765,817	87,523,790	2.3			
								74,944	1,807,581	2.4
2013/14										
Winter	35	308,524	10,564,147	3.4						
	224	965,479	61,816,164	6.4						
	345	3,600	249,568	6.9						
	352	16	1,926	12.0						
	379	25,132	796,919	3.2						
	355				1,221,665	51,334,078	4.2			
								503,112	21,181,526	4.2
2013/14	33	168,713	6,711,698	4.0						
Summer	34	126,565	5,034,999	4.0						
	35	628,045	18,090,811	2.9						
	224	1,015,113	61,506,215	6.1						
	345	2,356	181,614	7.7						
	352	9	1,175	13.1						
	379	190,646	5,353,815	2.8						
	355				4,578,951	117,982,912	2.6			
								12,551	928,186	7.4

<u>Export and Domestic Revenue MFR 4 (Revised)</u>

Re-file Dec 2013 Revised PUB/MH 1-008 (2014 Interim) updated to end of December 2014

- **Total Sales Data (CON/US/Merchant)**
- **Total MISO Sales (NEB Reporting)**
- **Opportunity Export tables, separately showing summer and winter components for each year**
- **Export Revenue tables showing Opportunity Bilateral, Day Ahead, Market, Real Time Market and Merchant Trading, separately showing summer and winter components for each year**
- **Fuel and Power purchases showing system merchant purchases, import power purchases (without wind), wind energy purchases & fuel purchases**
- **Transmission charges, separately showing summer and winter components for each year**

Information on total annual sales data and opportunity export sales can be found in Tab 9, Figures 9.6, 9.8 and 9.9. Information by season can be found in Tables 5 to 7 below. Information on NEB data on firm/interruptible exports by export permit number and imports can be found in the response to Domestic and Export Revenue MFR 3 and Appendix 9.1.

Information on annual export revenue, fuel and power purchases and transmission charges can be found in Tables 1 and 2. Information by season can be found in Tables 3 and 4 below.

Table 1

	EXPORT REVENUES														
	2010/11			2011/12			2012/13			2013/14			2014/15		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity															
Bilateral	1851	52	28.44	1923	50	26.02	1700	54	31.66	1471	53	36.07	1356	43	32.48
Market															
Day Ahead	3233	69	21.39	2720	52	18.68	2547	53	20.51	4251	109	25.77	3396	85	25.08
Real Time	1883	60	26.83	1859	50	23.24	1203	36	25.96	1336	32	30.94	915	25	26.18
Merchant	712	27	36.93	436	17	31.10	150	9	34.18	331	33	63.32	409	14	34.24

NOTE: 2014/15 is up to end of Dec 2014

Table 2

	Fuel and Power Purchased									
	2010/11		2011/12		2012/13		2013/14		2014/15	
	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)
System Merchant	712	24	436	14	150	6	331	19	409	11
Power Purchases	1154	34	1634	79	1584	71	1824	98	833	56
Transmission Charges		36		39		44		45		37
Fuel Purchases		12		14		12		14		6

NOTE: 2014/15 is up to end of Dec 2014

The tables below are split by season. Summer season consists of the months May to October. Winter season consists of the months April and November to March. The split was done this way so as to still tie to the fiscal year numbers provided previously.

Table 3

	EXPORT REVENUES																	
	2008/09			2009/10			2010/11			2011/12			2012/13			2013/14		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity Bilateral Winter	357	29	70.79	489	18	38.30	970	26	27.15	685	21	29.39	658	24	36.36	508	22	42.38
Opportunity Bilateral Summer	948	72	71.57	2139	42	19.95	881	26	29.87	1238	29	23.55	1042	30	28.65	963	31	32.67
Market Winter																		
Day Ahead	1087	41	37.80	1435	33	23.11	946	17	17.77	473	8	15.34	363	10	25.59	608	8	36.27
Real Time	322	20	53.81	771	32	32.17	846	23	25.59	734	18	22.44	393	10	27.66	422	13	45.51
Market Summer																		
Day Ahead	2953	81	27.58	1676	26	15.64	2287	52	22.88	2247	44	19.41	2184	43	19.56	3643	101	23.89
Real Time	368	40	48.31	1087	39	23.97	1037	37	27.76	1125	32	23.74	810	26	25.21	914	19	24.81
Merchant Winter	720	38	48.36	361	12	30.96	275	10	33.20	118	5	22.37	61	3	33.46	202	28	80.90
Merchant Summer	878	48	47.84	414	14	25.98	437	17	39.27	318	12	34.79	89	6	34.66	129	5	28.68

2014/15 is to end of Dec/14

Table 4

	Fuel and Power Purchased													
	2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15	
	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)
System Merchant Winter	720	36	359	12	275	8	118	3	61	2	202	15	169	5
System Merchant Summer	878	44	416	13	437	16	318	11	89	4	129	4	240	6
Power Purchases Winter	575	40	833	27	494	17	906	43	942	43	1233	66	382	23
Power Purchases Summer	406	17	487	6	660	17	728	36	642	28	591	32	451	33
Transmission Charges Winter		13		16		16		18		19		20		10
Transmission Charges Summer		8		17		20		21		25		25		27
Fuel Purchases Winter		10		10		8		8		7		10		2
Fuel Purchases Summer		8		3		4		6		5		4		4

2014/15 is to end of Dec/14

Table 5

TOTAL SALES									
	DEPENDABLE SALES			OPPORTUNITY SALES			SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2005/06 Winter	1,805	107	59.39	4,320	219	49.34	505	31	54.78
2005/06 Summer	2,239	133	59.14	5,983	291	47.23	414	32	66.51
2006/07 Winter	1,654	103	62.51	1,503	79	51.16	573	29	45.12
2006/07 Summer	2,000	115	57.32	4,747	216	45.09	633	31	41.81
2007/08 Winter	1,548	87	56.02	2,254	126	53.49	636	39	53.24
2007/08 Summer	2,373	122	51.39	4,845	202	40.47	626	33	45.03
2008/09 Winter	1,537	100	64.81	1,769	93	48.78	719	38	48.36
2008/09 Summer	2,550	133	52.49	4,270	194	41.87	879	48	47.84
2009/10 Winter	1,383	83	59.73	2,696	79	30.07	359	13	30.96
2009/10 Summer	1,880	103	54.98	4,901	105	19.75	383	12	25.98
2010/11 Winter	1,248	70	55.9	2,762	66	23.58	275	10	33.20
2010/11 Summer	2,129	102	48.27	4,205	115	25.61	437	17	39.27
2011/12 Winter	1,592	78	49.14	1,892	47	23.43	118	5	22.37
2011/12 Summer	2,150	97	45.05	4,610	105	21.96	318	12	34.79
2012/13 Winter	1,544	79	51.35	1,416	46	31.48	61	3	33.46
2012/13 Summer	2,092	98	46.72	4,035	100	22.94	89	6	34.66
2013/14 Winter	1,426	82	57.65	1,539	62	40.73	202	28	80.90
2013/14 Summer	2,053	100	48.45	5,519	141	25.63	129	6	28.68
2014/15 Winter	665	41	61.94	1,331	44	31.87	168	5	35.49
2014/15 Summer	1,904	99	52.05	4,336	115	25.38	241	9	33.35
2014/15 is to end of Dec/14									

Table 6

TOTAL U.S. SALES									
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2005/06 Winter	1,805	107	59.39	3,704	178	47.87	0	0	0.00
2005/06 Summer	2,239	133	59.14	5,175	223	43.57	0	0	0.00
2006/07 Winter	1,654	103	62.51	1,415	70	51.07	0	0	0.00
2006/07 Summer	2,000	115	57.32	4,462	200	44.72	0	0	0.00
2007/08 Winter	1,548	87	56.02	2,107	112	53.45	0	0	0.00
2007/08 Summer	2,373	122	51.39	4,511	177	40.14	0	0	0.00
2008/09 Winter	1,537	100	64.81	1,603	77	48.20	0	0	0.00
2008/09 Summer	2,550	133	52.49	4,019	160	41.61	0	0	0.00
2009/10 Winter	1,383	83	59.73	2,571	72	29.14	0	0	0.00
2009/10 Summer	1,880	103	54.98	4,653	88	19.25	33	2	0.00
2010/11 Winter	1,248	70	55.9	2,290	50	22.83	3	0.2	37.82
2010/11 Summer	2,129	102	48.27	3,772	96	25.46	2	0.1	37.82
2011/12 Winter	1,592	78	49.14	1,399	29	21.03	36	0.3	30.29
2011/12 Summer	2,150	97	45.05	4,218	88	21.39	70	3	40.92
2012/13 Winter	1,544	79	51.35	999	29	27.92	23	1	30.62
2012/13 Summer	2,092	98	46.72	3,691	84	22.35	40	1	29.49
2013/14 Winter	1,426	82	57.65	1,155	49	38.60	71	3	35.25
2013/14 Summer	2,053	100	48.45	5,181	133	25.21	114	4	28.42
2014/15 Winter	665	41	61.94	1,086	35	29.89	163	6	34.24
2014/15 Summer	1,904	99	52.05	3,862	99	24.63	237	7	33.26
2014/15 is to end of Dec/14									

Table 7

OPPORTUNITY EXPORTS						
	On Peak GWh	Off Peak GWh	On Peak Avg Price (CAD$)	Off Peak Avg Price (CAD$)	On Peak Revenues (CAD $M)	Off Peak Revenues (CAD $M)
2005/06 Winter	1,330	2,991	67.91	41.20	94	124
2005/06 Summer	1,813	4,170	76.48	34.34	151	141
2006/07 Winter	462	1,040	66.44	44.62	32	46
2006/07 Summer	1,510	3,238	66.08	35.33	103	114
2007/08 Winter	715	1,540	67.42	46.48	53	73
2007/08 Summer	1,497	3,347	65.84	26.96	109	93
2008/09 Winter	524	1,244	71.42	38.14	43	49
2008/09 Summer	1,278	2,993	72.13	25.84	110	85
2009/10 Winter	973	1,724	34.80	26.96	34	45
2009/10 Summer	1,524	3,376	29.00	15.24	50	55
2010/11 Winter	887	1,873	28.86	20.89	26	41
2010/11 Summer	1,381	2,826	33.93	21.33	50	64
2011/12 Winter	609	1,257	26.92	21.59	19	28
2011/12 Summer	1,319	3,293	28.68	19.03	40	65
2012/13 Winter	653	754	32.83	30.32	22	24
2012/13 Summer	1,512	2,532	28.60	19.50	47	53
2013/14 Winter	650	887	45.18	37.34	27	39
2013/14 Summer	1,842	3,679	33.87	21.43	55	82
2014/15 Winter	429	796	38.59	27.85	22	22
2014/15 Summer	1,360	3,082	33.00	22.03	45	70

2014/15 is to end of Dec/14

Export and Domestic Revenue MFR 6

File updated 2012 GRA II-105 (PUB/MH II-105) quarterly report generation summaries.

The table below provides an update to PUB/MH-II-105(a) by including quarterly and annual energy supply information for 2012/13 through December 2014. Wind purchases information is provided separate from imports for all quarters except 2014/15 Q3 where the data is aggregated as required by confidentiality restrictions on Manitoba Hydro on the release of wind generation data.

	Actual Results (GWh)	Hydraulic Generation	Thermal Generation	Wind Purchases	Imports
2014/15	Q1	8437	4	233	28
	Q2	9119	11	187	12
	Q3	8393	14	374	
	Annual	25950	30	420	40
2013/14	Q1	8536	24	229	38
	Q2	9189	20	154	39
	Q3	8990	36	257	135
	Q4	8546	51	294	431
	Annual	**35261**	**131**	**933**	**643**
2012/13	Q1	7257	5	218	124
	Q2	9028	27	182	4
	Q3	8136	40	222	207
	Q4	8726	11	229	193
	Annual	**33147**	**83**	**851**	**528**

Operating Expenses MFR 3

EFT staffing level information for the last five fiscal years and that forecast through the test years by business unit.

Please see the following tables for the EFTs by Business Unit from 2007/08 through 2016/17.

MANITOBA HYDRO
TOTAL EQUIVALENT FULL TIME (EFT) EMPLOYEES

(Straight Time & Overtime Combined)	**2007/08 Actual**	**2008/09 Actual**	**2009/10 Actual**	**2010/11 Actual**	**2011/12 Actual**	**2012/13 Actual**	**2013/14 Actual**	**2014/15 Forecast**	**2015/16 Forecast**	**2016/17 Forecast**
President & CEO	44	45	50	52	51	49	43	42	41	40
General Counsel & Corporate Secretary	36	35	37	38	40	40	44	45	44	42
Human Resources & Corporate Services	826	839	839	842	829	822	828	846	814	793
Corporate Relations	86	91	91	90	91	88	86	93	91	91
Finance & Regulatory	152	153	159	155	146	149	151	152	145	142
Generation Operations	1 006	1 027	1 079	1 139	1 166	1 164	1 196	1 180	1 165	1 160
Major Capital Projects	101	133	159	177	198	225	256	304	419	419
Transmission	1 620	1 717	1 784	1 845	1 841	1 878	1 904	1 914	1 918	1 881
Customer Service & Distribution	1 666	1 700	1 706	1 735	1 734	1 760	1 737	1 764	1 750	1 737
Customer Care & Energy Conservation	534	536	525	521	512	503	511	524	515	509
Total Corporation	**6 071**	**6 276**	**6 429**	**6 594**	**6 608**	**6 678**	**6 756**	**6 864**	**6 902**	**6 814**

The table above provides a summary of combined straight time and overtime EFTs for the Corporation.

The table below provides a summary of straight time EFTs by Business Unit from 2007/08 to 2016/17.

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES BY BUSINESS UNIT

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO	44	45	50	52	51	49	43	42	41	40
General Counsel & Corporate Secretary	36	35	37	38	40	40	44	45	44	42
Human Resources & Corporate Services	810	823	823	829	815	807	811	829	796	775
Corporate Relations	84	89	88	87	88	86	84	90	88	88
Finance & Regulatory	152	153	159	155	146	149	151	152	145	142
Generation Operations	918	934	976	1,039	1,061	1,067	1,096	1,086	1,074	1,070
Major Capital Projects	95	121	145	160	180	201	219	256	320	320
Transmission	1,498	1,586	1,646	1,702	1,704	1,741	1,762	1,771	1,779	1,742
Customer Service & Distribution	1,578	1,615	1,633	1,664	1,654	1,654	1,654	1,681	1,667	1,654
Customer Care & Energy Conservation	532	534	523	520	511	502	510	523	514	508
Total Corporation	**5,747**	**5,935**	**6,080**	**6,246**	**6,250**	**6,296**	**6,374**	**6,475**	**6,468**	**6,381**

The table below provides a summary of overtime EFTs by Business Unit from 2007/08 to 2016/17.

MANITOBA HYDRO
OVERTIME EQUIVALENT FULL TIME EMPLOYEES (EFT) BY BUSINESS UNIT

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO	0	0	0	0	0	0	0	0	0	0
General Counsel & Corporate Secretary	0	0	0	0	0	0	0	0	0	0
Human Resources & Corporate Services	16	16	16	13	14	15	17	17	18	18
Corporate Relations	2	2	3	3	3	2	2	3	3	3
Finance & Regulatory	0	0	0	0	0	0	0	0	0	0
Generation Operations	88	93	103	100	105	97	100	94	91	90
Major Capital Projects	6	12	14	17	18	24	37	48	99	99
Transmission	122	131	138	143	137	137	142	143	139	139
Customer Service & Distribution	88	85	73	71	80	106	83	83	83	83
Customer Care & Energy Conservation	2	2	2	1	1	1	1	1	1	1
Total Corporation	**324**	**341**	**349**	**348**	**358**	**382**	**382**	**389**	**434**	**433**

Operating Expenses MFR 4

Schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 2003/04 through the test years. This analysis should include the total labour and benefits capitalized for each year, total labour and benefits and the percentage of labour and benefits capitalized in a similar level of detail of PUB/MH l-5(c) R & PUB/MH 11-2 from the 2010 GRA.

Please see the following tables which provide information for each of the years 2003/04 through 2016/17.

i) Salaries, wages, overtime & benefits charged to operations as a percentage of total costs;

ii) Salaries, wages, overtime and benefits charged to operations as a percentage of domestic revenue;

iii) Salary and benefit costs capitalized.

i & ii) Salaries, wages, overtime & benefits charged to operations as a percentage of total costs and as a percentage of domestic revenue:

As discussed in Appendix 5.5, wages & salaries, overtime and employee benefits are associated with providing a pool of resources required for the operation, maintenance and capital construction activities of the Corporation. These costs are allocated to operations, maintenance and capital construction through the use of an hourly activity rate charged through the corporate time allocation system.

MANITOBA HYDRO
WAGES & SALARIES, OVERTIME & EMPLOYEE BENEFITS SCHEDULE
(in thousands of $)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Wages & Salaries, Overtime, Employee Benefits Charged To Operations	$286 872	$304 796	$312 629	$324 489	$333 584	$355 711	$373 084	$388 580	$409 867	$442 591	$465 460	$468 405	$469 188	$478 140
Total Costs (before capitalization)	$542 660	$569 749	$596 229	$615 849	$638 594	$687 149	$722 951	$748 471	$787 156	$841 225	$887 987	$924 766	$949 991	$967 104
Wages & Salaries, Overtime, Employee Benefits Charged to Operations as a percentage of Total Costs	53%	53%	52%	53%	52%	52%	52%	52%	52%	53%	52%	51%	49%	49%
Domestic Revenue (GCR)	$918 231	$938 954	$983 653	$1 023 613	$1 074 581	$1 126 812	$1 144 891	$1 200 381	$1 192 797	$1 341 011	$1 405 301	$1 406 745	$1 479 405	$1 544 112
Wages & Salaries, Overtime, Employee Benefits Charged to Operations as a percentage of Domestic Revenue	31%	32%	32%	32%	31%	32%	33%	32%	34%	33%	33%	33%	32%	31%

iii) Salary and benefit costs capitalized:

Activity charges form the basis for cost allocation to capital projects. Activity rates are comprised of a number of costs including salaries, wages and benefits, meals & accommodations, transportation costs, motor vehicle charges etc. The following provides an estimated amount of wages & salaries, overtime and employee benefits capitalized through activity charges.

MANITOBA HYDRO
CAPITALIZED WAGES & SALARIES, OVERTIME, EMPLOYEE BENEFITS
(in thousands of $)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Wages & Salaries, Overtime, Employee Benefits	$398,449	$423,093	$440,473	$457,233	$477,838	$509,592	$541,307	$571,238	$611,356	$658,082	$699,970	$724,993	$751,523	$766,109
Capitalized Wages & Salaries, Overtime, Employee Benefits	($111,577)	($118,297)	($127,844)	($132,744)	($144,253)	($153,881)	($168,223)	($182,659)	($201,489)	($215,491)	($234,510)	($256,588)	($282,335)	($287,969)
Capitalized Wages & Salaries, Overtime, Employee Benefits as a percentage of Total Wages & Salaries, Overtime, Employee Benefits	28%	28%	29%	29%	30%	30%	31%	32%	33%	33%	34%	35%	38%	38%

Note: Excludes capitalization through overhead.

Operating Expenses MFR 5

Schedule that average salary per EFT by business unit for the last five fiscal years through the test years.

Please see the following tables for the average salary per EFT by Business Unit and Division from 2009/10 through 2016/17.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY BUSINESS UNIT

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO	$ 96,282	$ 97,622	$ 103,183	$ 108,896	$ 111,813	$ 125,551	$ 130,486	$ 136,832
General Counsel & Corporate Secretary	86,823	88,938	91,820	95,496	98,168	99,831	103,648	107,519
Human Resources & Corporate Services	69,706	70,616	75,103	76,463	76,494	77,821	81,325	83,566
Corporate Relations	70,089	71,122	74,489	76,128	77,631	80,351	83,756	86,462
Finance & Regulatory	76,193	76,499	81,341	82,806	84,740	88,040	92,309	94,532
Generation Operations	71,487	72,436	76,682	78,820	80,225	82,803	86,391	88,512
Major Capital Projects	75,246	76,689	80,834	82,033	81,845	84,562	85,293	88,000
Transmission	66,517	67,688	71,658	74,326	75,710	77,961	82,006	85,110
Customer Services & Distribution	60,048	61,097	64,705	66,400	67,499	69,994	72,886	75,381
Customer Care & Energy Conservation	62,478	63,052	67,330	68,867	69,291	71,681	74,608	76,461
Business Unit Total	**66,545**	**67,600**	**71,689**	**73,723**	**74,791**	**77,168**	**80,585**	**83,129**

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY DIVISION

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO								
President & CEO Administration	$ 159,827	$ 152,757	$ 157,398	$ 175,645	$ 189,657	$ 214,044	$ 223,698	$ 233,595
Public Affairs	63,809	65,682	72,068	72,877	72,979	75,589	76,682	78,568
	$ 96,282	**$ 97,622**	**$ 103,183**	**$ 108,896**	**$ 111,813**	**$ 125,551**	**$ 130,486**	**$ 136,832**
General Counsel & Corporate Secretary								
VP General Counsel & Corp Secretary	$ 83,865	$ 84,336	$ 89,489	$ 92,201	$ 98,635	$ 100,495	$ 106,367	$ 110,098
Law Division	92,262	96,392	98,114	100,182	101,788	103,527	107,956	112,045
Internal Audit Division	80,270	80,851	84,234	90,193	92,405	93,648	94,904	98,492
	$ 86,823	**$ 88,938**	**$ 91,820**	**$ 95,496**	**$ 98,168**	**$ 99,831**	**$ 103,648**	**$ 107,519**
Human Resources & Corporate Services								
VP Human Resources & Corporate Services	$ 133,799	$ 132,413	$ 138,379	$ 149,603	$ 127,332	$ 134,266	$ 158,740	$ 162,620
Information Technology Services	75,848	76,622	81,129	82,601	83,012	85,010	88,188	90,477
Human Resources	73,035	73,244	78,642	79,782	82,100	81,595	84,875	87,122
Workplace Safety & Health and Corp Serv	60,533	62,138	65,890	67,274	67,615	69,566	72,884	74,873
Corporate Environmental Management	76,556	71,667	77,051	79,785	78,828	83,345	91,095	93,417
	69,706	**70,616**	**75,103**	**76,463**	**76,494**	**77,821**	**81,325**	**83,566**
Corporate Relations								
Aboriginal Relations	$ 60,147	$ 61,469	$ 65,749	$ 68,032	$ 68,945	$ 71,040	$ 74,183	$ 77,074
VP Corp Relations Administration	104,715	108,406	123,827	121,341	124,008	132,028	137,208	141,841
Corporate Planning & Strategic Review	97,754	94,012	93,688	95,398	98,185	101,362	109,040	113,247
	70,089	**71,122**	**74,489**	**76,128**	**77,631**	**80,351**	**83,756**	**86,462**
Finance & Regulatory								
Treasury	$ 72,647	$ 73,944	$ 76,284	$ 74,878	$ 79,216	$ 84,137	$ 87,949	$ 90,179
Corporate Risk Mgmt Department	84,998	93,196	100,976	103,310	100,892	103,692	108,230	111,025
Rates & Regulatory Affairs	77,711	78,675	84,017	87,308	86,210	89,047	92,811	94,209
Corporate Controller	77,205	76,174	79,943	80,818	81,316	84,642	87,677	89,891
VP Admin Finance & Regulatory	68,178	71,305	82,633	88,866	98,474	99,793	115,294	117,541
	76,193	**76,499**	**81,341**	**82,806**	**84,740**	**88,040**	**92,309**	**94,532**
Generation Operations								
VP Generation Operations Administration	$ 80,572	$ 78,213	$ 82,555	$ 91,106	$ 85,150	$ 80,007	$ 99,967	$ 102,167
Power Planning	83,007	83,747	88,154	88,839	91,577	94,980	100,228	102,760
Generation North	66,796	67,804	71,732	73,744	74,435	75,912	79,003	81,074
Generation South	65,398	66,524	70,447	72,379	73,489	76,051	79,083	80,909
Engineering Services	76,356	76,854	81,203	83,344	85,583	88,980	91,734	93,856
Power Sales & Operations	83,150	83,921	88,928	91,324	91,645	93,796	97,377	99,942
	71,487	**72,436**	**76,682**	**78,820**	**80,225**	**82,803**	**86,391**	**88,512**
Major Capital Projects								
Licensing & Relationship Management Div	$ 82,465	$ 81,646	$ 85,056	$ 84,081	$ 84,924	$ 89,354	$ 93,138	$ 96,321
Portfolio Projects Management	67,566	70,363	70,635	79,952	86,557	88,339	97,116	100,425
Bipole III Project	-	85,102	81,927	88,152	80,941	80,126	81,706	83,724
VP Major Capital Projects Administration	61,549	65,707	73,128	73,971	77,615	83,277	86,951	89,252
New Generation Construction	76,218	77,903	82,496	83,805	81,082	83,811	83,909	87,365
	75,246	**76,689**	**80,834**	**82,033**	**81,845**	**84,562**	**85,293**	**88,000**
Transmission								
HVDC	$ 68,505	$ 69,546	$ 73,957	$ 76,778	$ 78,809	$ 82,384	$ 86,641	$ 89,388
VP Transmission Administration	50,091	51,214	54,416	58,369	61,039	60,074	66,427	68,483
Transmission System Operations	76,549	77,900	81,442	83,987	84,577	88,023	92,146	95,412
Transmission Planning & Design	77,428	79,259	82,563	85,486	87,077	90,898	95,031	98,432
Transmission Construction & Line Mtce	65,015	65,714	70,356	71,708	72,187	73,093	74,478	76,968
Apparatus Maintenance	61,392	63,370	67,505	71,000	71,988	74,277	78,732	81,529
	66,517	**67,688**	**71,658**	**66,517**	**75,710**	**77,961**	**82,006**	**85,110**
Customer Services & Distribution								
Distribution Eng & Construction Division	$ 58,731	$ 59,377	$ 62,961	$ 65,566	$ 67,211	$ 69,081	$ 72,109	$ 74,522
Customer Service Operations - Wpg&North	60,840	61,821	65,207	66,201	67,653	69,464	72,068	74,515
Customer Service Operations - South	58,916	60,238	63,396	65,233	65,029	68,531	71,184	73,697
Business Support & Capital Asset Mgmt	66,484	67,830	73,252	72,527	74,882	79,075	82,821	85,689
VP Cust Service & Distribution Admin	125,973	124,256	125,419	133,000	138,198	140,372	157,684	162,668
	60,048	**61,097**	**64,705**	**66,400**	**67,499**	**69,994**	**72,886**	**75,381**
Customer Care & Energy Conservation								
Gas Supply	$ 79,781	$ 83,478	$ 89,980	$ 91,057	$ 93,189	$ 95,534	$ 101,291	$ 103,792
VP Customer Care & Energy Conservation	72,630	70,379	75,261	76,068	77,141	81,055	84,744	86,981
Industrial & Commercial Solutions	85,756	86,333	90,486	92,621	94,138	96,847	100,788	103,220
Consumer Marketing & Sales	56,488	57,369	62,008	63,535	63,455	65,586	68,436	70,112
Business Support Services	57,507	58,257	61,763	62,945	63,257	65,209	67,205	68,850
	62,478	**63,052**	**67,330**	**68,867**	**69,291**	**71,681**	**74,608**	**76,461**
Total	**66,545**	**67,600**	**71,689**	**73,723**	**74,791**	**77,168**	**80,585**	**83,129**

Operating Expenses MFR 8

A table/ matrix of EFT per 1,000 of GWh, per $millions of domestic revenue, per domestic customers for the years 2007/08 through the test years in a similar format to PUB/MH I-38 (a) (2012 GRA).

Please see the tables below for the information requested.

	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs	5,747	5,935	6,080	6,246	6,250
EFT per 1000 GWh of domestic supply	239.62	244.41	260.99	262.63	265.95
EFT per 1000 GWh of total supply	162.56	171.90	179.02	183.16	188.04
EFT per number of domestic customers	0.01	0.01	0.01	0.01	0.01
EFT per $ millions of domestic revenue	5.35	5.27	5.31	5.20	5.24

	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs	6,296	6,374	6,475	6,468	6,381
EFT per 1000 GWh of domestic supply	255.50	249.86	257.17	252.56	247.65
EFT per 1000 GWh of total supply	189.47	180.10	183.86	187.27	202.94
EFT per number of domestic customers	0.01	0.01	0.01	0.01	0.01
EFT per $ millions of domestic revenue	4.69	4.54	4.60	4.37	4.13

The underlying data can be found in the tables below.

Data Table					
	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs (Straight Time)	5,747	5,935	6,080	6,246	6,250
GWh of domestic Supply	23,985	24,285	23,295	23,783	23,499
GWh of total Supply	35,354	34,528	33,961	34,102	33,235
Electric Customers	521,599	527,472	532,359	537,299	542,681
Domestic revenue (in millions)	1,075	1,127	1,145	1,200	1,193

Data Table					
	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs (Straight Time)	6,296	6,374	6,475	6,468	6,381
GWh of domestic Supply	24,642	25,510	25,178	25,610	25,766
GWh of total Supply	33,230	35,392	35,217	34,538	31,443
Electric Customers	548,774	555,760	561,825	568,443	575,648
Domestic revenue (in millions)	1,341	1,405	1,407	1,479	1,544

<u>Operating Expenses MFR 9</u>

Schedule detailing the breakdown of Operating and Administrative expenses by division from 2003/04 through the test years. On this schedule provide two columns for the compound annual growth rate for the historical period and for the forecast period using the final year historical as a starting period. (PUB/MH 1-59 (b) - 2012 GRA).

Please see the following table detailing Operating, Maintenance and Administrative Costs by Division from 2004/05 to 2016/17. Please note that comparable information for 2003/04 is not readily available.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	Fiscal 2004/05-2013/14 Compounded Annual Growth	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Fiscal 2013/14-2016/17 Compounded Annual Growth
President & CEO															
President & CEO Administration	$ 7,690	$ 8,041	$ 8,579	$ 8,667	$ 8,658	$ 13,190	$ 10,351	$ 10,689	$ 8,850	$ 7,320	(0.5)	$ 8,753	$ 8,916	$ 8,986	7.1
Public Affairs	2,804	2,856	3,288	2,939	3,189	3,582	3,938	3,682	3,798	3,567	2.7	3,556	3,554	3,474	(0.9)
	$ 10,494	**$ 10,898**	**$ 11,867**	**$ 11,606**	**$ 11,846**	**$ 16,773**	**$ 14,289**	**$ 14,371**	**$ 12,648**	**$ 10,887**	**0.4**	**$ 12,309**	**$ 12,469**	**$ 12,460**	**4.6**
General Counsel & Corporate Secretary															
VP General Counsel & Corp Secretary	$ 2,932	$ 3,640	$ 3,147	$ 2,729	$ 3,709	$ 3,541	$ 3,063	$ 3,218	$ 5,402	$ 5,847	8.0	$ 5,305	$ 5,327	$ 5,386	(2.7)
Law Division	$ 1,207	$ 1,287	$ 1,390	$ 1,515	$ 1,575	$ 1,925	$ 2,019	$ 2,032	$ 1,961	$ 1,767	4.3	$ 2,068	$ 1,999	$ 1,957	3.5
Internal Audit Division	$ 886	$ 936	$ 1,095	$ 1,194	$ 1,243	$ 1,278	$ 1,388	$ 1,449	$ 1,378	$ 1,702	7.5	$ 1,871	$ 1,895	$ 1,889	3.5
	$ 5,024	**$ 5,863**	**$ 5,631**	**$ 5,439**	**$ 6,526**	**$ 6,745**	**$ 6,470**	**$ 6,699**	**$ 8,741**	**$ 9,316**	**7.1**	**$ 9,244**	**$ 9,222**	**$ 9,232**	**(0.3)**
Human Resources & Corporate Services															
VP Human Resources & Corporate Services	$ 1,160	$ 1,294	$ 1,903	$ 1,820	$ 1,901	$ 2,673	$ 2,357	$ 2,436	$ 1,943	$ 1,091	(0.7)	$ 1,120	$ 1,130	$ 1,150	1.8
Information Technology Services	$ 29,273	$ 29,884	$ 34,413	$ 32,709	$ 33,959	$ 35,349	$ 34,181	$ 35,539	$ 38,013	$ 40,817	3.8	$ 42,890	$ 43,310	$ 43,778	2.4
Human Resources	$ 10,376	$ 10,448	$ 10,645	$ 11,092	$ 10,633	$ 10,001	$ 9,806	$ 10,300	$ 11,637	$ 18,270	6.5	$ 17,851	$ 17,629	$ 17,239	(1.9)
Workplace Safety & Health and Corp Serv	$ 33,322	$ 34,877	$ 35,834	$ 36,904	$ 39,362	$ 41,264	$ 41,282	$ 40,385	$ 41,630	$ 45,042	3.4	$ 45,347	$ 45,230	$ 44,773	(0.2)
Corporate Environmental Management	$ 324	$ 273	$ 419	$ 454	$ 601	$ 1,002	$ 943	$ 972	$ 938	$ 816	10.8	$ 851	$ 863	$ 873	2.3
	$ 74,454	**$ 76,775**	**$ 83,214**	**$ 82,978**	**$ 86,456**	**$ 90,288**	**$ 88,568**	**$ 89,631**	**$ 94,161**	**$ 106,036**	**4.0**	**$ 108,058**	**$ 108,161**	**$ 107,814**	**0.6**
Corporate Relations															0.0
Aboriginal Relations	$ 2,968	$ 4,653	$ 4,324	$ 4,331	$ 4,473	$ 3,929	$ 4,101	$ 2,475	$ 3,372	$ 3,537	2.0	$ 3,605	$ 3,658	$ 3,722	1.7
Administration	535	844	896	914	1,047	769	638	550	584	743	3.7	1,001	833	704	(1.8)
Corporate Planning & Strategic Review	4,501	4,614	4,601	4,746	4,524	6,237	6,256	5,400	5,774	4,638	0.3	5,452	5,518	5,607	6.5
	$ 8,004	**$ 10,110**	**$ 9,821**	**$ 9,991**	**$ 10,044**	**$ 10,934**	**$ 10,994**	**$ 8,424**	**$ 9,730**	**$ 8,918**	**1.2**	**$ 10,059**	**$ 10,008**	**$ 10,033**	**4.0**
Finance & Regulatory															
Treasury	$ 2,267	$ 2,146	$ 1,887	$ 2,001	$ 2,067	$ 1,957	$ 1,909	$ 1,915	$ 1,978	$ 2,165	(0.5)	$ 2,237	$ 2,355	$ 2,394	3.4
Corporate Risk Mgmt Department	150	153	442	460	566	593	811	938	921	1,069	24.4	1,123	1,135	1,019	(1.6)
Rates & Regulatory Affairs	3,105	2,913	3,037	2,999	2,918	3,388	3,139	3,152	3,276	3,334	0.8	3,617	3,534	3,450	1.1
Corporate Controller	8,544	8,606	8,190	8,910	9,492	10,522	10,014	9,590	9,946	10,018	1.8	10,521	10,603	10,652	2.1
VP Admin Finance & Regulatory	882	917	1,043	953	962	1,277	1,184	1,250	1,359	1,923	9.0	2,536	2,477	2,667	11.5
	$ 14,947	**$ 14,735**	**$ 14,600**	**$ 15,322**	**$ 16,005**	**$ 17,737**	**$ 17,057**	**$ 16,845**	**$ 17,480**	**$ 18,510**	**2.4**	**$ 20,033**	**$ 20,104**	**$ 20,182**	**2.9**
Generation Operations															
VP Generation Operations Administration	$ 4,269	$ 3,207	$ 3,419	$ 2,513	$ 2,708	$ 2,860	$ 2,557	$ 2,838	$ 2,405	$ 1,805	(9.1)	$ 1,970	$ 2,163	$ 2,206	6.9
Power Planning	2,739	2,086	2,555	3,131	4,211	5,867	6,764	7,053	7,003	6,508	10.1	8,261	10,127	10,439	17.1
Generation North	26,363	27,002	27,046	28,853	31,578	27,169	28,560	28,386	32,358	36,441	3.7	36,006	36,538	37,356	0.8
Generation South	41,569	40,267	41,542	43,274	45,891	49,707	49,850	51,425	51,819	56,156	3.4	55,671	55,294	55,686	(0.3)
Engineering Services	11,217	10,190	10,085	10,253	10,528	11,520	10,686	9,876	18,540	19,817	6.5	21,270	21,692	21,909	3.4
Power Sales & Operations	8,870	10,120	11,346	11,625	12,578	12,969	12,770	13,364	13,408	14,646	5.7	15,111	15,364	15,364	1.6
	$ 95,025	**$ 92,873**	**$ 95,994**	**$ 99,650**	**$ 107,494**	**$ 110,091**	**$ 111,187**	**$ 112,944**	**$ 125,533**	**$ 135,373**	**4.0**	**$ 138,290**	**$ 141,178**	**$ 142,959**	**1.8**

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	Fiscal 2004/05-2013/14 Compounded Annual Growth	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Fiscal 2013/14-2016/17 Compounded Annual Growth
Major Capital Projects															
Licensing & Relationship Management Div	$ 865	$ 581	$ 696	$ 354	$ 764	$ 119	$ 573	$ 150	$ 1,462	$ 3,406	16.4	$ 3,725	$ 1,593	$ 1,665	(21.2)
Portfolio Projects Management	-	42	58	57	(34)	219	364	344	390	500	0.0	586	1,069	1,104	30.2
Bipole III Project	-	-	-	-	-	0	(69)	(41)	109	(10)	0.0	278	374	292	(407.1)
VP Major Capital Projects Administration	-	-	-	-	26	(29)	(198)	(103)	268	11	0.0	531	904	907	331.6
New Generation Construction	(134)	(306)	(447)	(228)	(2)	(184)	(477)	(159)	682	477	(215.1)	519	629	620	9.1
	$ 731	**$ 318**	**$ 307**	**$ 184**	**$ 754**	**$ 126**	**$ 193**	**$ 190**	**$ 2,912**	**$ 4,384**	**22.0**	**$ 5,638**	**$ 4,568**	**$ 4,588**	**1.5**
Transmission															
HVDC	$ 17,653	$ 17,282	$ 19,177	$ 19,128	$ 21,659	$ 23,170	$ 22,927	$ 24,698	$ 26,136	$ 28,642	5.5	$ 28,966	$ 29,200	$ 29,973	1.5
VP Transmission Administration	2,779	8,534	10,180	10,151	14,459	15,630	17,868	18,636	24,245	26,025	28.2	23,740	23,707	21,224	(6.6)
Transmission System Operations	27,102	27,639	29,779	28,453	31,408	33,185	32,415	29,857	35,875	37,839	3.8	38,540	38,540	39,442	1.4
Transmission Planning & Design	4,836	4,855	5,212	3,402	5,219	4,162	3,419	4,936	9,181	8,406	6.3	8,959	8,834	8,991	2.3
Transmission Construction & Line Mtce	14,349	14,395	14,861	15,952	15,964	17,219	16,239	15,998	20,084	21,191	4.4	21,123	22,251	22,540	2.1
Apparatus Maintenance	28,913	29,082	31,327	33,834	36,281	35,742	36,272	37,024	40,922	41,808	4.2	42,783	42,806	43,825	1.6
	$ 95,632	**$101,786**	**$110,537**	**$110,920**	**$124,991**	**$129,107**	**$129,140**	**$131,148**	**$156,442**	**$163,910**	**6.2**	**$164,112**	**$165,338**	**$165,995**	**0.4**
Customer Services & Distribution															
Distribution Eng & Construction Division	$ 5,620	$ 4,752	$ 3,632	$ 5,091	$ 5,188	$ 5,314	$ 3,808	$ 2,335	$ 12,264	$ 11,150	7.9	$ 11,127	$ 9,845	$ 9,717	(4.5)
Customer Service Operations - Wpg&North	43,697	44,249	42,043	44,838	48,048	49,635	47,815	49,287	51,114	50,109	1.5	52,106	51,115	52,122	1.3
Customer Service Operations - South	36,469	40,520	38,076	38,535	40,767	44,651	43,678	43,695	50,188	47,778	3.0	49,702	48,663	48,722	0.7
Business Support & Capital Asset Mgmt	8,145	8,811	9,982	11,264	11,701	12,565	12,427	15,747	16,876	20,601	10.9	21,025	21,572	21,816	1.9
Administration	-	560	277	544	163	1,130	1,259	1,575	1,887	1,264	0.0	963	1,080	1,113	(4.1)
	$ 93,931	**$ 98,892**	**$ 94,011**	**$100,273**	**$105,867**	**$113,295**	**$108,988**	**$112,639**	**$132,330**	**$130,902**	**3.8**	**$134,922**	**$132,275**	**$133,490**	**0.7**
Customer Care & Marketing															
Gas Supply	$ 1,789	$ 2,027	$ 1,981	$ 2,058	$ 2,248	$ 2,356	$ 2,428	$ 2,488	$ 2,572	$ 2,865	5.4	$ 2,846	$ 2,855	$ 2,881	0.2
VP Customer Care & Energy Conservation	4,257	3,678	3,869	3,961	4,192	5,770	4,867	4,998	5,089	4,812	1.4	5,225	5,242	5,290	3.2
Industrial & Commercial Solutions	3,167	2,203	2,810	3,031	2,457	3,043	2,464	2,870	4,735	5,705	6.8	5,832	5,851	5,904	1.1
Consumer Marketing & Sales	9,874	9,741	9,913	8,905	9,545	10,642	11,518	11,630	13,107	14,263	4.2	14,591	14,637	14,771	1.2
Business Support Services	23,624	25,000	24,741	21,037	21,023	21,120	20,703	22,012	24,121	27,708	1.8	29,867	27,779	27,990	0.3
	$ 42,711	**$ 42,649**	**$ 43,314**	**$ 38,991**	**$ 39,465**	**$ 42,931**	**$ 41,980**	**$ 43,997**	**$ 49,624**	**$ 55,353**	**2.9**	**$ 58,361**	**$ 56,364**	**$ 56,837**	**0.9**
Corporate Allocations & Adjustments	(28,933)	(29,127)	(30,441)	(29,098)	(24,158)	(39,374)	(23,941)	(18,385)	(13,196)	(21,617)	(3.2)	(26,177)	(26,678)	(19,274)	(3.8)
Operating & Administration Charged to Centra	(55,232)	(53,085)	(53,505)	(56,270)	(59,803)	(60,951)	(60,644)	(62,117)	(63,735)	(66,808)	2.1	(67,829)	(66,691)	(67,818)	0.5
Capitalized Overhead	(58,174)	(62,028)	(61,887)	(67,289)	(61,198)	(60,151)	(47,336)	(53,084)	(69,720)	(74,449)	2.8	(81,265)	(24,578)	(24,824)	(30.7)
Electric OM&A, including Accounting Changes	**$298,613**	**$310,658**	**$323,465**	**$322,698**	**$364,288**	**$377,551**	**$396,946**	**$403,304**	**$462,952**	**$480,717**	**5.4**	**$485,755**	**$541,740**	**$551,675**	**4.7**

Operating Expenses MFR 10

Schedule detailing the capitalized OM&A costs by business unit for the years 2003/04 through the test years.

Please see the following table detailing the costs capitalized by Business Unit for the years 2004/05 to 2016/17. Please note that comparable information for 2003/04 is not readily available.

MANITOBA HYDRO
COSTS CAPITALIZED BY BUSINESS UNIT **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
President & CEO	$ -	$ -	$ 30	$ 24	$ 21	$ 22	$ 43	$ 48	$ 275	$ 53	$ -	$ -	$ -
General Counsel & Corporate Secretary	201	132	192	242	353	270	232	404	639	1,299	905	922	948
Human Resources & Corporate Services	12,097	12,856	8,796	10,362	10,114	10,653	12,426	12,399	13,062	13,564	16,580	16,115	16,256
Corporate Relations	2,289	3,104	4,035	3,974	4,901	5,052	4,950	5,315	4,233	4,118	4,757	4,847	4,992
Finance & Regulatory	461	393	246	246	390	164	96	112	273	940	399	271	274
Generation Operations	18,613	19,459	22,671	22,352	23,595	28,729	33,686	41,687	34,670	40,289	41,561	40,345	41,125
Major Capital Projects	4,126	4,547	6,376	10,264	12,692	16,801	18,574	21,801	24,593	28,451	33,977	48,711	49,562
Transmission	48,770	51,675	50,451	58,696	61,971	70,353	78,316	83,094	73,232	79,235	88,013	94,171	95,863
Customer Service & Distribution	64,974	69,727	74,874	76,163	80,943	82,375	85,041	93,016	84,835	88,319	92,588	97,926	99,955
Customer Care & Energy Conservation	6,198	8,566	9,321	10,007	10,191	9,878	10,179	10,775	9,007	9,746	11,135	13,673	13,812
	$ 157,730	**$ 170,459**	**$ 176,992**	**$ 192,331**	**$ 205,169**	**$ 224,297**	**$ 243,545**	**$ 268,651**	**$ 244,819**	**$ 266,013**	**$ 289,917**	**$ 316,982**	**$ 322,787**

<u>Operating Expenses MFR 11</u>

A comparison of the OM&A per customer for actual and current IFF with that presented at last GRA for comparable years for each year through the test years. (PUB/MH I-8 (c) 2010 GRA).

<u>ANSWER</u>:

Please see the following for a comparison of the OM&A cost per customer presented at the last GRA for comparable years from fiscal 2013 to fiscal 2017.

	Actual		Forecast - IFF14		
	2013	**2014**	**2015**	**2016**	**2017**
OM&A expense 'electric only' (in millions of $)	463	481	486	542	552
# of Customers	548 774	555 760	558 871	565 222	572 144
OM&A (electric only) per customer (in dollars)	844	865	870	959	965
OM&A (electric only) per customer, excluding Accounting Changes	701	701	698	697	695

	Forecast - IFF12 (2012/13 & 2013/14 Electric GRA)				
	2013	**2014**	**2015**	**2016**	**2017**
OM&A expense 'electric only' (in millions of $)	455	471	544	556	567
# of Customers	548 944	555 955	563 047	570 205	577 419
OM&A (electric only) per customer (in dollars)	829	847	965	975	982

			Change		
(in millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**
OM&A (electric only) per customer (in dollars)	14	18	(96)	(16)	(17)

The increase in cost per customer for 2013 and 2014 compared to forecast is primarily due to changes in the discount rate impacting pension and other benefits. The decrease in 2015 is a result of the delay in the implementation of IFRS from 2015 in IFF12 to 2016 in IFF14. The overall decrease in the test years forecast years reflects Manitoba Hydro's commitment to cost containment.

Operating Expenses MFR 13

A schedule which compares Operating, Maintenance and Administrative Cost for fiscal years subject to last GRA to actual results presented in this application with the forecast results provided at the Prior GRA in both dollar change and % change by:

- **a. Cost element**
- **b. Business unit**
- **c. And explain any differences over 5%.**

Please see the following schedules which compare Operating, Maintenance and Administrative costs for 2012/13 and 2013/14 to the forecast provided at the prior GRA (IFF12).

Differences over 5% and $500,000 have been explained.

a) Cost Element Schedules and Explanations:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2012/13 Actual	2012/13 Forecast	2012/13 Variance	%	Ref
Wages & Salaries	$ 466 165	$ 476 570	$ 10 404	2%	
Overtime	61 031	56 005	(5 025)	-9%	1
Employee Benefits	130 886	117 264	(13 622)	-12%	2
Sub-Total	658 082	649 839	(8 243)		
Less: Labour & Benefits Charged to Capital	(215 491)	(216 412)	(921)	0%	
Labour & Benefits Charged to Operations	442 591	433 427	(9 164)	-2%	
Employee Safety & Training	4 463	4 914	452	9%	
Travel Expenses	31 194	32 405	1 211	4%	
Motor Vehicle	29 516	25 954	(3 562)	-14%	3
Materials & Tools	24 806	27 173	2 367	9%	4
Consulting & Professional Fees	10 817	11 639	822	7%	5
Construction & Maintenance Services	16 259	18 706	2 447	13%	6
Building & Property Services	25 644	22 399	(3 245)	-14%	7
Equipment Maintenance & Rentals	14 680	14 476	(204)	-1%	
Consumer Services	5 050	5 284	234	4%	
Computer Services	849	909	60	7%	
Collection Costs	4 261	4 347	86	2%	
Customer & Public Relations	6 731	6 849	118	2%	
Sponsored Memberships	1 767	1 081	(686)	-63%	8
Office & Administration	13 874	15 263	1 390	9%	9
Communication Systems	1 817	1 683	(134)	-8%	
Research & Development Costs	3 372	3 509	137	4%	
Miscellaneous Expense	2 040	1 213	(827)	-68%	10
Contingency Planning	-	(0)	(0)	0%	
Operating Expense Recovery	(13 997)	(9 787)	4 210	-43%	11
Sub-Total	183 143	188 018	4 876		
Less: Other Costs Charged to Capital	(29 327)	(29 453)	(125)	0%	
Other Costs Charged to Operations	153 815	158 566	4 750	3%	
Total	596 406	591 993	(4 413)	-1%	
Capitalized Overhead	(69 720)	(69 384)	335	0%	
Operating and Administration Charged to Centra	(63 735)	(67 300)	(3 565)	5%	12
OM&A Attributable to Electric Operations	**$ 462 952**	**$ 455 309**	**$ (7 643)**	**-2%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2012/13 VARIANCE EXPLANATIONS

Ref	Cost Element	Fav (Unfav)	Explanation
1	Overtime	(5,025)	Primarily due to unplanned storm restoration work.
2	Employee Benefits	(13,622)	Primarily due to the impact of a lower discount rate on pension and other benefit costs.
3	Motor Vehicle	(3,562)	Primarily due to higher fuel costs as a result of an increase in market prices and greater volumes partly due to storm restoration work.
4	Materials & Tools	2,367	Mainly due to lower maintenance requirements than anticipated at various generating stations partly due to availability of resources.
5	Consulting & Professional Fees	822	Mainly due to delays in various engagements such as environmental monitoring of river sediment contamination, the deferral of IFRS implementation and the security audit.
6	Construction & Maintenance Services	2,447	Primarily due to lower maintenance requirements at generating and converter stations partly due to availability of resources, less hydrometric monitoring than anticipated as well as lower LIDAR services for vegetation management.
7	Building & Property Services	(3,245)	Mainly due to increased contracted meal and accommodation services for internal staff and external contractors in the Gillam area. These costs are partially offset in Operating Expense Recovery.
8	Sponsored Memberships	(686)	Primarily as a result of higher membership dues for professional staff and greater than anticipated membership fees for the Canadian Electrical Association (CEA).
9	Office & Administration	1,390	Partly due to lower telecommunication costs as a result of Mobile Workforce Management as well as lower overall requirements due to cost saving measures.
10	Miscellaneous Expense	(827)	Primarily due to the expensing of costs as a result of the cancellation of various capital projects.
11	Operating Expense Recovery	4,210	Primarily due to higher recovery of costs from subsidiaries as well as the recovery of costs (charged to Building and Property Services) for meal and accommodation services provided to external parties.
12	Operating and Administration Charged to Centra	(3,565)	Lower activities than planned in various programs such as burner tip services and ground maintenance partly due to vacancies.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

	2013/14 Actual	2013/14 Forecast	2013/14 Variance	%	Ref
Wages & Salaries	$ 480 511	$ 486 101	$ 5 590	1%	
Overtime	62 365	57 126	(5 239)	-9%	13
Employee Benefits	157 094	126 002	(31 092)	-25%	14
Sub-Total	699 970	669 229	(30 742)		
Less: Labour & Benefits Charged to Capital	(234 510)	(221 083)	13 427	-6%	15
Labour & Benefits Charged to Operations	465 460	448 146	(17 314)	-4%	
Employee Safety & Training	4 596	5 013	417	8%	
Travel Expenses	31 915	33 053	1 139	3%	
Motor Vehicle	29 670	26 473	(3 197)	-12%	16
Materials & Tools	27 920	27 716	(204)	-1%	
Consulting & Professional Fees	14 657	11 872	(2 785)	-23%	17
Construction & Maintenance Services	16 775	19 080	2 305	12%	18
Building & Property Services	28 978	22 847	(6 131)	-27%	19
Equipment Maintenance & Rentals	15 007	14 766	(241)	-2%	
Consumer Services	5 277	5 389	112	2%	
Computer Services	678	927	249	27%	
Collection Costs	3 125	4 434	1 309	30%	20
Customer & Public Relations	5 610	6 986	1 376	20%	21
Sponsored Memberships	1 249	1 103	(146)	-13%	
Office & Administration	14 724	15 569	845	5%	22
Communication Systems	1 963	1 717	(246)	-14%	
Research & Development Costs	2 195	3 579	1 384	39%	23
Miscellaneous Expense	1 485	1 237	(248)	-20%	
Contingency Planning	-	0	0	0%	
Operating Expense Recovery	(17 808)	(9 983)	7 825	-78%	24
Sub-Total	188 016	191 779	3 763		
Less: Other Costs Charged to Capital	(31 503)	(29 699)	1 804	-6%	15
Other Costs Charged to Operations	156 513	162 080	5 567	3%	
Total	621 973	610 226	(11 748)	-2%	
Capitalized Overhead	(74 446)	(70 772)	3 674	-5%	25
Operating and Administration Charged to Centra	(66 810)	(68 800)	(1 990)	3%	
OM&A Attributable to Electric Operations	**$ 480 717**	**$ 470 654**	**$ (10 063)**	**-2%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
2013/14 VARIANCE EXPLANATIONS

Ref	Cost Element	Fav (Unfav)	Explanation
13	Overtime	(5 239)	Primarily due to resources deployed to provide assistance following the TransCanada Pipelines (TCPL) explosion and Toronto Hydro storm. These costs are offset in Operating Expense Recovery. In addition, increased capital construction requirements primarily for Bipole III, Pointe du Bois Spillway & NFAT activities, which are offset by an increase in Labor & Benefits Charged to Capital.
14	Employee Benefits	(22 845)	Primarily due to the impact of a lower discount rate on pension and other benefit costs.
15	Labour, Benefits & Other Costs Charged to Capital	13 427	Mainly due to the growth in the overall capital program, primarily for projects such as Bipole III, Pointe du Bois Spillway & NFAT.
16	Motor Vehicle	(3 197)	Primarily due to greater fuel costs and higher costs associated with external motor vehicle repair as a result of increased shop rates, greater volume of units being repaired and cost increases for motor vehicle parts.
17	Consulting & Professional Fees	(2 785)	Primarily due to increased legal fees associted with the Risk Management review and community participation costs for NCN expenses related to the Wuskwatim partnership.
18	Construction & Maintenance Services	2 305	Mainly due to lower requirements for station maintenance, special maintenance and LiDAR services for vegetation management.
19	Building & Property Services	(6 131)	Mainly due to increased contracted meal and accommodation services for internal staff and external contractors in the Gillam area as well as costs for the operations of the Wuskwatim staffhouse for a full year. These costs are partially offset in Operating Expense Recovery.
20	Collection Costs	1 309	Primarily due to fewer uncollectible accounts receivable written off and higher recoveries of bad debts than expected.
21	Customer & Public Relations	1 376	Mainly due to lower sponsorships, donations and grants and promotional and advertising expenditures as a result of cost saving measures.
22	Office & Administration	845	Partly due to lower telecommunication costs as a result of Mobile Workforce Management as well as lower overall requirements due to cost saving measures.
23	Research & Development Costs	1 384	Funding for various R&D programs lower than anticipated.
24	Operating Expense Recovery	7 825	Mainly due to the recovery of costs for restoration work performed after the TCPL explosion and the Toronto Hydro storm. In addition, higher recovery of costs (charged to Building and Property Services) for meal and accommodation services provided to external parties and greater recoveries from subsidiaries.
25	Capitalized Overhead	3 674	Related to higher capital construction activities.

b) Business Unit Schedules and Explanations:

MANITOBA HYDRO

OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2012/13 Actual	2012/13 Forecast	2012/13 Variance	%	Ref
President & CEO	$ 12,648	$ 12,966	$ 318	2%	
General Counsel & Corporate Secretary	8,741	7,401	(1,340)	-18%	1
Human Resources & Corporate Services	94,161	95,579	1,418	1%	
Corporate Relations	9,730	10,526	796	8%	2
Finance & Regulatory	17,480	17,915	435	2%	
Generation Operations	125,533	127,537	2,004	2%	
Major Capital Projects	2,912	4,027	1,115	28%	3
Transmission	156,442	151,102	(5,340)	-4%	
Customer Service & Distribution	132,330	134,004	1,674	1%	
Customer Care & Energy Conservation	49,624	51,319	1,694	3%	
Business Unit Subtotal	**609,602**	**612,377**	**2,775**	**0%**	
Corporate Allocations & Adjustments	(13,196)	(20,384)	(7,188)	-35%	4
Operating & Administration Charged to Centra	(63,735)	(67,300)	(3,565)	-5%	5
Capitalized Overhead	(69,720)	(69,384)	335	0%	
OM&A Costs Attributable to Electric Operations	**$ 462,952**	**$ 455,309**	**$ (7,643)**	**-2%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2012/13 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
1	General Counsel & Corporate Secretary	(1,340)	Primarily due to higher external legal fees associated with Risk Management review and Export Power Sale contracts, as well as greater insurance claims than anticipated.
2	Corporate Relations	796	Primarily due to a lower requirement for community participation and reduced funding for R&D projects.
3	Major Capital Projects	1,115	Primarily due to numerous vacancies across the Business Unit.
4	Corporate Allocations & Adjustments	(5,937)	Primarily due to the impact of the change in the discount rate on pension and other benefits.
5	Operating & Administration Charged to Centra	(3,565)	Lower activities than planned in various programs such as burner tip services and ground maintenance work partly due to vacancies.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

	2013/14 Actual	2013/14 Forecast	2013/14 Variance	%	Ref
President & CEO	$ 10,887	$ 13,226	$ 2,339	18%	6
General Counsel & Corporate Secretary	9,316	7,549	(1,767)	-23%	7
Human Resources & Corporate Services	106,036	97,491	(8,545)	-9%	8
Corporate Relations	8,918	10,736	1,818	17%	9
Finance & Regulatory	18,510	18,273	(237)	-1%	
Generation Operations	135,373	130,088	(5,285)	-4%	
Major Capital Projects	4,384	4,108	(276)	-7%	
Transmission	163,910	154,124	(9,786)	-6%	10
Customer Service & Distribution	130,902	136,684	5,782	4%	
Customer Care & Energy Conservation	55,353	52,345	(3,008)	-6%	11
Business Unit Subtotal	**643,590**	**624,624**	**(18,966)**	**-3%**	
Corporate Allocations & Adjustments	(21,617)	(14,398)	7,218	50%	12
Operating & Administration Charged to Centra	(66,810)	(68,800)	(1,990)	-3%	
Capitalized Overhead	(74,446)	(70,772)	3,674	5%	13
OM&A Costs Attributable to Electric Operations	**$ 480,717**	**$ 470,654**	**$ (10,063)**	**-2%**	

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT
2013/14 VARIANCE EXPLANATIONS

Ref	Business Unit	Fav (Unfav)	Explanation
6	President & CEO	2,339	Primarily due to reorganizations which resulted in the transfer of EFTs to Human Resources & Corporate Services, General Counsel & Corporate Secretary and Corporate Relations. In addition, reduced memberships, donations & grants.
7	General Counsel & Corporate Secretary	(1,767)	Primarily due to higher external legal fees associated with the Risk Management review, a transfer of EFTs from President & CEO, and higher benefit costs.
8	Human Resources & Corporate Services	(8,545)	Primarily due to higher benefit costs, centralization of the internal training program, and a transfer of EFTs from President & CEO and Generation Operations.
9	Corporate Relations	1,818	Primarily due to lower Research & Development funding and higher vacancies.
10	Transmission	(9,786)	Primarily due to higher benefit costs.
11	Customer Care & Energy Conservation	(3,008)	Primarily due to the transfer of the meter reading function from CS&D and higher benefit costs.
12	Corporate Allocations & Adjustments	7,218	Primarily due to the impact of the change in the discount rate on pension and other benefits.
13	Capitalized Overhead	3,674	Related to higher capital construction activities.

Operating Expenses MFR 14

A schedule detailing the operating and administration charged to Centra and Other Affiliates for each of the last five fiscal years through the test years (actual/forecast) by:

a. **Cost Element**
b. **Business Unit**

Please see the following schedules detailing the operating and administration costs charged to Centra for each of the last five fiscal years through the test years (actual/forecast) by cost element and business unit.

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY COST ELEMENT

($000's)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)
Activity Charges	$ 44,410	$ 45,918	$ 46,568	$ 37,865	$ 41,003	$ 42,891	$ 39,372	$ 40,391	
Primary Costs:									
External Course, Awards	24	26	21	9	5	7	7	7	
Material	1,294	1,184	1,170	1,304	1,154	1,313	1,084	1,084	
Travel	87	102	79	110	94	84	86	86	
Donations, Grants & Sponsorships	333	393	476	442	364	298	298	298	
Memberships	170	176	188	193	61	212	212	212	
Bad Debt & Collection Expense	2,086	1,613	1,435	1,200	1,104	1,472	1,472	1,472	
Office Administration & Other	1,562	1,557	1,608	1,623	1,579	1,778	1,777	1,777	
Computer Equipment & Maintenance	563	522	452	470	617	725	733	733	
Meter Reading Charges (primarily MHUS)	2,425	1,949	2,130	2,078	2,115	2,065	2,065	2,065	
Banking/Cash Management Services	222	220	255	242	268	284	284	284	
Construction & Maintenance Services	1,240	947	1,823	1,210	1,135	1,223	1,221	1,221	
Purchased Services	1,988	1,772	1,506	1,661	1,747	1,730	1,520	1,519	
Promotional Items/Customer Incentives	25	57	71	19	16	5	5	5	
Gas-PUB & Advisory Services	766	491	496	481	468	450	450	450	
Operating Expense Recoveries	(537)	(620)	(598)	(6)	-	-	-	-	
Other	4	-	4	5	(8)	3	4	4	
Total Primary Costs	**12,251**	**10,390**	**11,116**	**11,041**	**10,719**	**11,650**	**11,219**	**11,217**	**-1.0%**
Corporate Allocations & Adjustments	1,460	1,660	1,718	8,276	7,263	5,742	18,169	18,320	
Overhead	10,735	7,870	7,990	9,532	10,317	10,796	(0)	(0)	
Total Program Costs	**68,857**	**65,838**	**67,392**	**66,714**	**69,302**	**71,079**	**68,760**	**69,928**	**0.0%**
Depreciation, Interest and Taxes	(7,906)	(5,194)	(5,275)	(2,978)	(2,492)	(3,250)	(2,068)	(2,110)	
Operating & Administration Charged to Centra	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 63,735**	**$ 66,810**	**$ 67,829**	**$ 66,691**	**$ 67,818**	**1.3%**

MANITOBA HYDRO
CENTRA GAS PROGRAM COSTS BY BUSINESS UNIT

($000's)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Average Annual % Inc/(Dec)
President & CEO	$ 814	$ 891	$ 877	$ 510	$ 327	$ 491	$ 469	$ 470	
General Counsel & Corporate Secretary	336	41	242	128	147	160	134	134	
Human Resources & Corporate Services	1,141	1,208	1,195	1,298	1,476	1,477	1,451	1,478	
Corporate Relations	72	40	6	48	49	-	-	-	
Finance & Regulatory	2,800	2,530	2,142	2,244	2,470	1,808	1,594	1,567	
Generation Operations	220	477	317	441	512	796	574	575	
Transmission	255	250	99	121	204	186	153	158	
Customer Service & Distribution	40,288	37,941	39,565	34,761	35,509	38,045	28,315	29,067	
Customer Care & Energy Conservation	21,471	20,801	21,231	18,885	21,343	22,373	17,901	18,160	
Business Unit Subtotal	**67,397**	**64,178**	**65,674**	**58,437**	**62,038**	**65,337**	**50,590**	**51,608**	**-3.5%**
Corporate Allocations & Adjustments	1,460	1,660	1,718	8,276	7,263	5,742	18,169	18,320	
Depreciation, Interest and Taxes	(7,906)	(5,194)	(5,275)	(2,978)	(2,492)	(3,250)	(2,068)	(2,110)	
Operating & Administration Charged to Centra	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 63,735**	**$ 66,810**	**$ 67,829**	**$ 66,691**	**$ 67,818**	**1.3%**

As per the tables above, the average annual increase of operating and administration costs including accounting changes is 1.3%, which is below inflationary levels.

The decrease from 2014/15 to 2015/16 is a result of the IFRS requirement to harmonize its accounting policy with respect to costs associated with the Meter Sampling, Exchange and Testing program. Prior to the transition to IFRS these costs were capitalized for the Electric operations and expensed for the Gas operations.

This decrease is partially offset by the expensing of overhead costs no longer eligible for capitalization under IFRS and is reflected in the increase to Corporate Allocations and Adjustments.

Payments to Government MFR 1

Provide a schedule of actual and forecast payments made to the Province and Municipalities for five historical years and for the 20-year forecast period.

Please see the following schedule for all payments to municipalities and the Province for 2010 through 2034.

Payments to the Province and Municipalities (Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Sinking Fund Admin. Fee	Capital Taxes	Payroll Taxes	Provincial Mitigation or Settlement Obligations (1)	Municipal GILT and Business Taxes	Gross Electricity Operations Revenue	Gross Export Revenue	Total Provincial Payments (GILT & Business Tax Not Included)	Provincial Payments as a Percentage of Gross Revenue
2010	114	72	1	46	9	0	20	1,583	427	$ 242	15%
2011	114	77	-	48	10	0	20	1,616	398	$ 249	15%
2012	111	82	-	52	10	1	21	1,573	363	$ 256	16%
2013	110	90	-	55	11	1	21	1,733	353	$ 267	15%
2014	118	96	-	60	11	0	23	1,914	439	$ 285	15%
2015	117	105	-	64	12	8	24	1,831	409	$ 306	17%
2016	115	118	-	70	12	0	25	1,928	434	$ 315	16%
2017	104	140	-	83	12	0	26	2,008	450	$ 339	17%
2018	104	167	-	96	12	0	26	2,101	457	$ 379	18%
2019	103	197	-	104	13	0	27	2,222	479	$ 417	19%
2020	105	213	-	104	13	0	28	2,352	514	$ 435	18%
2021	115	225	-	103	13	0	28	2,732	817	$ 456	17%
2022	118	232	-	109	13	0	29	2,944	943	$ 472	16%
2023	118	231	-	107	14	0	29	3,054	959	$ 470	15%
2024	118	233	-	117	14	0	30	3,182	987	$ 482	15%
2025	117	236	-	117	14	0	31	3,298	996	$ 484	15%
2026	117	236	-	117	15	0	31	3,342	928	$ 485	15%
2027	118	238	-	117	15	0	32	3,475	944	$ 488	14%
2028	117	239	-	117	15	0	33	3,575	921	$ 488	14%
2029	117	240	-	117	16	0	33	3,702	920	$ 490	13%
2030	117	241	1	117	16	0	34	3,849	927	$ 492	13%
2031	118	239	1	118	16	0	35	3,980	911	$ 492	12%
2032	117	232	-	118	17	0	35	4,065	901	$ 484	12%
2033	117	232	-	120	17	0	36	4,145	883	$ 486	12%
2034	118	232	1	120	17	0	37	4,248	884	$ 488	11%

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $8 million remain to be paid in fiscal 2015 and future years.

Payments to Government MFR 2

A schedule detailing the calculation of the Net Hydro Guarantee fee for five historical years and through the twenty year forecast period.

The following schedule details the calculation of the net Manitoba Hydro Provincial Debt Guarantee Fee (PGF) for 2010/11 through to 2033/34.

Payments to Government MFR 2

MANITOBA HYDRO
Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Actual 2011 (1)	Actual 2012 (1)	Actual 2013 (1)	Actual 2014 (1)	Actual 2015 (1)	Forecast 2016 (2)	Forecast 2017 (2)	Forecast 2018 (2)	Forecast 2019 (2)	Forecast 2020 (2)	Forecast 2021 (2)	Forecast 2022 (2)
Long Term Debt Balance	8,538	8,628	9,348	9,937	10,944	12,083	14,204	17,070	19,939	21,549	22,810	23,560
Short Term Debt Balance	-	-	-	-	-	83	142	55	111	134	74	7
Trust Investment from Pre-Financing	(554)	(100)	-	-	(90)	-	-	-	-	-	-	-
PGF Assessed On	7,984	8,528	9,348	9,937	10,854	12,167	14,345	17,125	20,050	21,683	22,884	23,567
Guarantee Fee Rate	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %
Amount Paid to Province	80	85	93	99	109	122	143	171	201	217	229	236
Portion Allocated to Centra	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Net MB Hydro Provincial Debt Guarantee Fee	**77**	**82**	**90**	**96**	**105**	**118**	**140**	**167**	**197**	**213**	**225**	**232**

Notes: (1) The fee calculation is based on ending principal par value debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in Payments to Government MFR 2 represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.

(2) US Dollar long term debt balance at March 31, 2015 was converted at forecast year end exchange rate of 1.10 for the assessment of the 2016 PGF.
US Dollar long term debt balances at March 31, 2016, 2017, 2018 and 2019 were converted at forecast year end exchange rate of 1.12 for the assessment of the PGF for years 2017, 2018, 2019 and 2020.
US Dollar long term debt balances at March 31, 2020 and beyond were converted at forecast year end exchange rate of 1.10 for the assessment of the PGF for years 2021 and beyond.

Payments to Government MFR 2

MANITOBA HYDRO
Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Forecast 2023 (2)	Forecast 2024 (2)	Forecast 2025 (2)	Forecast 2026 (2)	Forecast 2027 (2)	Forecast 2028 (2)	Forecast 2029 (2)	Forecast 2030 (2)	Forecast 2031 (2)	Forecast 2032 (2)	Forecast 2033 (2)	Forecast 2034 (2)
Long Term Debt Balance	23,445	23,584	23,884	23,882	24,232	24,432	24,432	24,572	24,472	23,772	23,772	23,742
Short Term Debt Balance	40	145	152	173	2	-	62	-	-	-	-	-
Trust Investment from Pre-Financing	-	-	-	-	-	-	-	-	-	-	-	-
PGF Assessed On	23,485	23,729	24,036	24,055	24,234	24,432	24,494	24,572	24,472	23,772	23,772	23,742
Guarantee Fee Rate	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %
Amount Paid to Province	235	237	240	241	242	244	245	246	245	238	238	237
Portion Allocated to Centra	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(5)	(5)	(5)	(6)	(6)
Net MB Hydro Provincial Debt Guarantee Fee	**231**	**233**	**236**	**236**	**238**	**239**	**240**	**241**	**239**	**232**	**232**	**232**

Notes: (1) The fee calculation is based on ending principal par value debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in Payments to Government MFR 2 represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.

(2) US Dollar long term debt balance at March 31, 2015 was converted at forecast year end exchange rate of 1.10 for the assessment of the 2016 PGF.
US Dollar long term debt balances at March 31, 2016, 2017, 2018 and 2019 were converted at forecast year end exchange rate of 1.12 for the assessment of the PGF for years 2017, 2018, 2019 and 2020.
US Dollar long term debt balances at March 31, 2020 and beyond were converted at forecast year end exchange rate of 1.10 for the assessment of the PGF for years 2021 and beyond.

Payments to Government MFR 3

Provide a schedule detailing the calculation of the water rental payments for the last five historical years and through the twenty year forecast period. (Similar to PUB/MH 1-24 (c) 2010 GRA)

Water Rental Calculation

	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	
Megawatt-Hours Generated (million mWh)	33.8	34.0	33.2	33.1	35.3	
Converted to Horsepower-years	5.6	5.6	5.5	5.5	5.8	(1)
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32	(2)
Calculated Water Annual Rental ($ million)	$ 113.0	$ 113.8	$ 110.8	$ 110.8	$ 117.9	
Minimum Rental Adjustment	1.0	0.3				(3)
Other Adjustment				(0.4)		(4)
Total Water Rentals	$ 114.0	$ 114.1	$ 110.8	$ 110.4	$ 117.9	

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally , the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as 2010 and 2011, it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Water rentals relating to the Wuskwatim Generating Station were calculated at a reduced rate during the commissioning process. The full rental rate of $20.32 per Horsepower-year was charged commencing October 6, 2012.

Water Rental Calculation

	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019
Megawatt-Hours Generated (million mWh)	35.1	34.4	31.1	31.1	30.9
Converted to Horsepower-years	5.8	5.7	5.1	5.1	5.1
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 117.4	$ 115.0	$ 103.9	$ 104.1	$ 103.3

	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Megawatt-Hours Generated (million mWh)	31.5	34.5	35.3	35.3	35.3
Converted to Horsepower-years	5.2	5.7	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 105.1	$ 115.4	$ 117.9	$ 117.8	$ 117.8

	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029
Megawatt-Hours Generated (million mWh)	35.1	35.1	35.2	35.1	35.1
Converted to Horsepower-years	5.8	5.8	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 117.5	$ 117.3	$ 117.8	$ 117.5	$ 117.5

	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Megawatt-Hours Generated (million mWh)	35.1	35.2	35.1	35.1	35.2
Converted to Horsepower-years	5.8	5.8	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 117.5	$ 117.7	$ 117.4	$ 117.4	$ 117.5

Capital Expenditures-Depreciation MFR 2 (Revised)

A schedule detailing the breakdown of the balances by component of capitalized costs (wages, overhead etc.) in construction work and process, for each major Generation and Transmission project consistent with the last Annual Report.

Please see the following table:

Breakdown of Major Generation and Transmission projects by capitalized cost components
As at March 31, 2014
(in millions of dollars)

	Activity Charges	Overhead	Interest	Material	Other	Total
Kettle Improvements & Upgrades	1.1	0.2	0.4	0.4	1.6	3.7
Wuskwatim - Staffhouse (WPLP)	0.8	0.2	0.1	-	1.3	2.4
Keeyask	74.2	18.5	236.7	5.7	582.1	917.2
Conawapa - Generation	3.7	0.7	2.6	0.1	7.2	14.3
Conawapa - Licensing	45.2	11.5	83.2	4.2	142.7	286.8
Conawapa - PR280 & PR290 Upgrades	-	-	-	-	0.1	0.1
Pointe du Bois Spillway Replacement	33.4	7.6	33.9	2.2	325.7	402.8
Pointe du Bois - Transmission	2.8	0.6	0.5	2.4	1.2	7.5
Pointe du Bois - Communications	0.1	-	-	-	-	0.1
Kelsey Improvements & Upgrades	0.5	0.1	0.1	0.2	2.4	3.3
Bipole III - Transmission Line	27.6	6.6	20.5	11.1	70.4	136.2
Bipole III-Converter Stations	35.8	8.1	25.4	36.4	195.3	301.0
Bipole III - Collector Lines	5.4	1.4	0.9	4.8	20.6	33.1
Bipole III-Community Develop Initiative	-	-	-	-	53.9	53.9
Riel 230/500kV Station	30.1	7.2	35.3	84.0	130.9	287.5
Ont to Man 100MW Firm Import U/G - Trans	0.1	-	-	-	0.1	0.2
Manitoba-Minnesota Transmission Project	1.1	0.3	0.1	-	0.9	2.4
Grand Rapids Hatchery Upgrade & Expansn	0.3	-	-	-	0.6	0.9
Major Generation and Transmission	262.2	63.0	439.7	151.5	1 537.0	2 453.4
Base Capital and Other						482.8
Great Northern Transmission Line	0.5	0.1	0.3	-	5.9	6.8
Annual Report - Note 9						2 943.0

Capital Expenditures-Depreciation MFR 3 (Revised)

Provide a breakdown of the total balance of Generation & Transmission costs by each major project and identify the balance related to base capital, in a similar level of detail is PUB/MH I- 45 (b).

Please see the following table:

Breakdown of Major Generation and Transmission projects by capitalized cost components
As at March 31, 2013
(in millions of dollars)

	Activity Charges	Overhead	Interest	Material	Other	Total
Kettle Improvements & Upgrades	0.7	0.1	0.2	0.3	1.4	2.7
Wuskwatim - Staffhouse (WPLP)	0.4	0.1	-	-	0.6	1.1
Keeyask	53.9	13.3	191.4	4.5	376.7	639.8
Conawapa - Generation	2.6	0.5	1.8	0.1	7.1	12.1
Conawapa - Licensing	37.9	9.6	67.3	4.2	129.7	248.7
Pointe du Bois Spillway Replacement	25.6	5.7	17.6	1.9	117.4	168.2
Pointe du Bois - Transmission	2.3	0.6	0.4	2.4	0.5	6.2
Pointe du Bois - Communications	0.3	0.1	-	0.1	0.1	0.6
Kelsey Improvements & Upgrades	10.3	2.7	5.6	4.4	8.8	31.8
Bipole III - Transmission Line	18.8	4.4	14.9	3.6	43.2	84.9
Bipole III-Converter Stations	23.3	4.9	12.8	31.6	83.9	156.5
Bipole III - Collector Lines	2.4	0.6	0.3	2.1	1.5	6.9
Riel 230/500kV Station	20.2	4.6	20.9	71.2	97.1	214.0
Ont to Man 100MW Firm Import U/G - Trans	0.1	-	-	-	0.1	0.2
Manitoba-MinnesotaTransmission Project	0.2	-	0.2	-	1.0	1.4
Major Generation and Transmission	199.0	47.2	333.4	126.4	869.1	1 575.1
Base Capital and Other						391.9
Annual Report - Note 9						1 967.0

Capital Expenditures-Depreciation MFR 4

Provide a schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance each Major Generation & Transmission Projects in each of the forecast years and the (electric) capital coverage ratio for the last five historical years and through the 20 year forecast period in a similar format to PUB/MH 1-22 (c) from the 2012 GRA.

Please see the following table for the cash flow from electric operations, electric base capital spending as well as the net financing requirements for Major Generation & Transmission Projects and for sustaining capital expenditures for 2009/10 through 2033/34.

It should be noted that the attached schedule is for illustrative purposes only and the allocations of cash flow from operations are notional. Manitoba Hydro does not allocate cash flow from operations or proceeds from debt for specific uses in practice.

		Actuals						Forecast										
	For the year ended March 31	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	**Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	554.0	661.0	558.2	587.0	571.0	598.1	482.3	440.6	469.1	521.6	613.4	699.2
2	**Sustaining Capital Spending**	357.0	349.0	405.4	442.6	465.2	432.7	470.1	570.9	577.0	609.6	547.3	547.4	547.5	572.6	554.7	562.8	571.0
3	**Excess Cash Flow after Sustaining Capital Spending (1-2)**	242.0	304.0	122.6	107.4	52.8	121.3	190.9	(12.7)	10.0	(38.6)	50.8	(65.1)	(106.9)	(103.6)	(33.0)	50.6	128.2
4	**Capital Coverage Ratio (1/2)**	1.68	1.87	1.30	1.24	1.11	1.28	1.41	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22
5	**Major New Generation & Transmission**	473.0	538.5	674.0	657.5	567.8	600.3	983.7	1 451.7	1 913.9	2 463.5	2577.8	1530.9	884.0	426.2	196.1	116.6	110.0
6	**Financing Required to Fund MNG&T & Sustaining Capital**	231.0	234.5	551.4	550.1	515.0	479.0	792.8	1 464.4	1 903.9	2 502.1	2527.0	1596.0	991.0	529.7	229.2	66.0	0.0

	For the year ended March 31	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
1	**Cash Flow from Operations**	787.0	818.3	942.7	1024.1	1146.3	1288.1	1431.7	1560.9	1655.5	1774.8
2	**Sustaining Capital Spending**	621.1	624.5	637.3	648.6	674.7	665.0	703.5	710.5	723.8	734.9
3	**Excess Cash Flow after Sustaining Capital Spending (1-2)**	165.9	193.8	305.4	375.5	471.5	623.1	728.2	850.4	931.7	1039.9
4	**Capital Coverage Ratio (1/2)**	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41
5	**Major New Generation & Transmission**	107.8	110.7	97.8	81.3	70.5	60.7	66.5	71.6	98.4	175.0
6	**Financing Required to Fund MNG&T & Sustaining Capital**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Finance Expense-Debt Levels MFR 4

A schedule that details for the last five fiscal year through the 20 year current forecast a summary of total interest and finance cost incurred/ forecasted by major category [debt charges, foreign currency gains/losses etc.] both capitalized and expended in a similar level of detail provided in PUB/MH 1-35 (2010 GRA).

The attached schedule for the fiscal years 2009/10 to 2033/34 conforms to the categorization of finance expense as shown in the Application in Schedule 5.1.5. This schedule groups the components of finance expense into three primary categories:

1. Total Interest on Short & Long Term Debt,
2. Interest Allocated to Construction, and
3. Sinking Fund and Other Adjustments.

The Corporation's net interest expense is the total interest on short & long term debt minus the interest allocated to construction.

For a fuller discussion of Finance Expense, please see Section 5.6 of Tab 5 of this Application.

MANITOBA HYDRO
Summary of Total Finance Expense
($ millions CAD)

	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022
Interest on Short & Long Term Debt													
Gross Interest	$ 472	$ 472	$ 490	$ 515	$ 528	$ 554	$ 627	$ 756	$ 903	$ 995	$ 1,076	$ 1,120	$ 1,137
Provincial Guarantee Fee	72	77	82	90	96	105	118	140	167	197	213	225	232
Amortization of (Premiums), Discounts, and Transaction Costs	(11)	3	0	0	2	3	3	2	2	2	2	3	4
Intercompany Interest Receivable	(16)	(16)	(17)	(19)	(19)	(21)	(23)	(27)	(32)	(37)	(42)	(45)	(34)
Total Interest on Short & Long Term Debt	**517**	**535**	**555**	**587**	**608**	**640**	**725**	**871**	**1,040**	**1,157**	**1,248**	**1,303**	**1,338**
Interest Allocated to Construction	**(98)**	**(136)**	**(167)**	**(138)**	**(140)**	**(146)**	**(207)**	**(316)**	**(437)**	**(388)**	**(341)**	**(112)**	**(12)**
Interest Earned on Sinking Fund	(24)	(17)	(10)	(10)	(24)	(0)	(2)	(9)	(19)	(24)	(24)	(21)	(19)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	6	1	(0)	2	(19)	(11)	(17)	(11)	(15)	(6)	(9)	(10)	(12)
Revaluation of Dual Currency Bonds	(31)	4	3	3	2	1	1	1	1	1	1	1	2
Corporate Allocation	(18)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
Other Amortization	20	20	24	27	28	29	29	29	29	30	30	50	47
Total Finance Expense	**$ 373**	**$ 388**	**$ 385**	**$ 452**	**$ 435**	**$ 495**	**$ 510**	**$ 548**	**$ 581**	**$ 752**	**$ 887**	**$ 1,194**	**$ 1,326**

	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Interest on Short & Long Term Debt												
Gross Interest	$ 1,125	$ 1,141	$ 1,149	$ 1,154	$ 1,163	$ 1,168	$ 1,171	$ 1,161	$ 1,143	$ 1,067	$ 1,050	$ 1,032
Provincial Guarantee Fee	231	233	236	236	238	239	240	241	239	232	232	232
Amortization of (Premiums), Discounts, and Transaction Costs	3	1	2	2	2	2	3	3	3	4	4	4
Intercompany Interest Receivable	(26)	(28)	(29)	(30)	(32)	(33)	(34)	(36)	(37)	(39)	(39)	(40)
Total Interest on Short & Long Term Debt	**1,333**	**1,347**	**1,358**	**1,362**	**1,371**	**1,376**	**1,379**	**1,368**	**1,349**	**1,264**	**1,247**	**1,228**
Interest Allocated to Construction	**(14)**	**(17)**	**(20)**	**(24)**	**(25)**	**(17)**	**(20)**	**(20)**	**(24)**	**(25)**	**(27)**	**(38)**
Interest Earned on Sinking Fund	(7)	(9)	(13)	(16)	(30)	(44)	(59)	(69)	(82)	(62)	(76)	(91)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(7)	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	2	2	2	2	-	-	-	-	-	-	-	-
Corporate Allocation	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(17)	(16)	(16)	(16)	(16)
Other Amortization	46	44	43	42	41	40	39	38	37	36	34	33
Total Finance Expense	**$ 1,334**	**$ 1,349**	**$ 1,351**	**$ 1,348**	**$ 1,338**	**$ 1,337**	**$ 1,321**	**$ 1,301**	**$ 1,263**	**$ 1,197**	**$ 1,161**	**$ 1,116**

Finance Expense-Debt Levels MFR 5

A continuity schedule of the short and long-term debt for the fiscal years 2004 to 2032 detailing the retirement of existing debt and the issue of new debt, include the debt ratio. Indicate the proportion of short-term debt to total debt for each of the years.

The attached schedule of short and long term debt conforms to the Corporation's financial statement presentation, with measurement in Canadian dollars (CAD) and which in accordance with accounting standards specify the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates).

Long term debt refers to borrowings which have a term to maturity equal to or greater than one year, and is made up of fixed rate debt with non-variable interest rates and floating rate debt which have a periodic interest rate resetting mechanism prior to maturity. Note that some of the long term debt issues may be retired at their maturity. Manitoba Hydro will consider the availability of sinking fund withdrawals and surplus cash to reduce the required refinancing of maturing debt.

Short term debt refers to borrowings with non-variable interest rates which have a term to maturity of less than one year. The short term borrowing program is a $500 million credit facility with a primary objective to safeguard the Corporation from liquidity risk by providing sufficient liquidity for the Corporation's temporary cash requirements. Manitoba Hydro uses its short term debt line to fund its working capital requirements and to bridge the timing between long term debt issues.

See the Debt Management Strategy in Appendix 3.7 for additional information regarding the Corporation's debt financing requirements and strategies.

Finance Expense - Debt Levels MFR5

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Actuals to December 31, 2014
(in $ millions Canadian Dollars)

Long Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Forecast 2015**	**Forecast 2016**	**Forecast 2017**	**Forecast 2018**
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,034	14,159	17,028
Long Term Debt Proceeds	1,013	300	180	173	981	423	1,425	915	698	807	1,320	1,983	2,400	3,200	3,200
Long Term Debt Matured	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(242)	(613)	(835)	(312)	(334)	(330)
Carrying Value Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	38	176	18	37	3	3
Closing Balance	**7,390**	**7,204**	**7,169**	**7,227**	**7,571**	**8,187**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,034**	**14,159**	**17,028**	**19,901**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Forecast 2015**	**Forecast 2016**	**Forecast 2017**	**Forecast 2018**
Opening Balance	128	93	59	-	148	-	100	-	-	-	-	-	83	142	55
Increase (Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	-	-	83	59	(87)	56
Closing Balance	**93**	**59**	**-**	**148**	**-**	**100**	**-**	**-**	**-**	**-**	**-**	**83**	**142**	**55**	**111**

Total Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Forecast 2013**	**Forecast 2014**	**Forecast 2015**	**Forecast 2016**	**Forecast 2017**	**Forecast 2018**
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,034	14,159	17,028	19,901
Short Term Debt	93	59		148	-	100	-	-	-	-	-	83	142	55	111
Total Debt	**7,483**	**7,263**	**7,169**	**7,375**	**7,571**	**8,287**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,117**	**14,301**	**17,083**	**20,012**
Proportion of Short Term Debt to Total Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	0%	0%	1%	1%	0%	1%
Consolidated Debt Ratio	87%	85%	81%	80%	73%	77%	73%	73%	74%	75%	76%	77%	81%	83%	84%

Finance Expense - Debt Levels MFR5

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Actuals to December 31, 2014
(in $ millions Canadian Dollars)

Long Term Debt	**Forecast 2019**	**Forecast 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023**	**Forecast 2024**	**Forecast 2025**	**Forecast 2026**	**Forecast 2027**	**Forecast 2028**	**Forecast 2029**	**Forecast 2030**	**Forecast 2031**	**Forecast 2032**	**Forecast 2033**	**Forecast 2034**
Opening Balance	19,901	21,509	22,772	23,527	23,414	23,557	23,859	23,861	24,215	24,417	24,420	24,563	24,466	23,769	23,760	23,734
Long Term Debt Proceeds	2,800	1,600	1,600	600	600	600	400	800	200	-	200	-	-	-	-	-
Long Term Debt Matured	(1,195)	(315)	(850)	(718)	(461)	(300)	(402)	(450)	-	-	(60)	(100)	(700)	(13)	(30)	-
Carrying Value Adjustments*	3	(22)	5	5	5	3	4	4	2	3	3	3	3	4	4	4
Closing Balance	**21,509**	**22,772**	**23,527**	**23,414**	**23,557**	**23,859**	**23,861**	**24,215**	**24,417**	**24,420**	**24,563**	**24,466**	**23,769**	**23,760**	**23,734**	**23,738**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	**Forecast 2019**	**Forecast 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023**	**Forecast 2024**	**Forecast 2025**	**Forecast 2026**	**Forecast 2027**	**Forecast 2028**	**Forecast 2029**	**Forecast 2030**	**Forecast 2031**	**Forecast 2032**	**Forecast 2033**	**Forecast 2034**
Opening Balance	111	134	74	7	40	145	152	173	2	-	62	-	-	-	-	-
Increase (Decrease)	23	(60)	(67)	33	105	7	21	(171)	(2)	62	(62)	-	-	-	-	-
Closing Balance	**134**	**74**	**7**	**40**	**145**	**152**	**173**	**2**	**-**	**62**	**-**	**-**	**-**	**-**	**-**	**-**

Total Debt	**Forecast 2019**	**Forecast 2020**	**Forecast 2021**	**Forecast 2022**	**Forecast 2023**	**Forecast 2024**	**Forecast 2025**	**Forecast 2026**	**Forecast 2027**	**Forecast 2028**	**Forecast 2029**	**Forecast 2030**	**Forecast 2031**	**Forecast 2032**	**Forecast 2033**	**Forecast 2034**
Long Term Debt	21,509	22,772	23,527	23,414	23,557	23,859	23,861	24,215	24,417	24,420	24,563	24,466	23,769	23,760	23,734	23,738
Short Term Debt	134	74	7	40	145	152	173	2	-	62	-	-	-	-	-	-
Total Debt	**21,643**	**22,846**	**23,534**	**23,454**	**23,702**	**24,012**	**24,034**	**24,217**	**24,417**	**24,482**	**24,563**	**24,466**	**23,769**	**23,760**	**23,734**	**23,738**
Proportion of Short Term Debt to Total Debt	1%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	85%	86%	87%	88%	89%	89%	89%	89%	88%	87%	86%	84%	82%	79%	76%	73%

Finance Expense-Debt Levels MFR 6

Term sheets related to long term debt issued in the last two fiscal years.

The attached information provides the terms for Manitoba Hydro's actual new and amended long term debt financings for fiscal years 2012/13, 2013/14 and 2014/15 up to December 31, 2014. See Finance Expense – Debt Levels MFR 7 for a complete summary listing of the entire debt portfolio at December 31, 2014.

Terms for New and Amended Long Term Debt
(April 1, 2012 to December 31, 2014)

The terms for Manitoba Hydro's new and amended long term debt financings are provided for fiscal years 2012/13, 2013/14 and 2014/15 (up to December 31, 2014).

2012/13 Total long term financings for the year were CAD $1,300 million, made up of:

- $754.9 million for new borrowing requirements.
- $41.1 million to refinance maturing long term debt.
- $504.0 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year, per quarter, were as follows:

Quarter 1 On June 5, 2012, Manitoba Hydro secured long term debt series **GA** for CAD $300 million and a March 5, 2043 maturity date. GA was issued at a discount with proceeds of $296.4 million (net of commissions), a fixed rate coupon of 3.350%, and an all-in-yield of 3.413%. The debt was issued to finance new borrowing requirements.

Quarter 2 On July 12, 2012, Manitoba Hydro secured long term debt series **FN-3** for CAD $50 million and a March 5, 2050 maturity date. FN-3 was issued at a premium with proceeds of $65.3 million (net of commissions), a fixed rate coupon of 4.700%, and an all-in-yield of 3.281%. The debt was issued to finance new borrowing requirements.

On July 31, 2012, Manitoba Hydro secured long term debt series **C129** for CAD $50 million and a September 5, 2052 maturity date. C129 was issued at a discount with proceeds of $49.7 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in-yield of 3.178%. The debt was issued to finance new borrowing requirements.

On September 6, 2012, Manitoba Hydro secured long term debt series **GC** for USD $300 million and a September 6, 2022 maturity date. The issue was swapped to CAD $296.4 million and a floating rate coupon of 3 month BA + 0.499%. The debt was issued to finance new borrowing requirements.

Quarter 3 On December 3, 2012, Manitoba Hydro secured long term debt series **C132** for CAD $200 million and an April 2, 2018 maturity date. The debt, which was swapped to floating rate debt, was issued to refinance debt series ER-1 ($200 million). A forward fixed interest rate swap that was previously linked to debt series ER-1 was re-linked to the C132 underlying refinancing, which amended the fixed rate on the debt stream to 7.515%.

Quarter 4 On January 22, 2013, Manitoba Hydro secured long term debt series C132-2 for CAD $104 million and an April 2, 2018 maturity date. The debt, which was swapped to floating rate debt, was issued to refinance debt series C125-1 ($85 million) and C125-2 ($19 million). Forward fixed interest rate swaps that were previously linked to debt series C125-1 and C125-2 were re-linked to the C132-2 underlying refinancing, which amended the fixed rate on the debt streams to 4.997% (**C132-2A**) and 4.927% (**C132-2B**).

On March 13, 2013, Manitoba secured long term debt series GD for CAD $300 million and a September 5, 2018 maturity date. The first $100 million of the debt (**GD**) was issued to partially refinance debt series ER-2 ($41.1 million), with the remaining $58.9 million to finance new borrowing requirements. GD was issued at a discount with proceeds of $99.46 million (net of commissions), a fixed rate coupon of 1.850%, and an all-in yield of 1.954%. The residual $200 million of the debt, which was swapped to floating rate debt, was issued to refinance debt series C112-1 ($100 million) and C112-2 ($100 million). Forward fixed interest rate swaps that were previously linked to debt series C112-1 and C112-2 were re-linked to the GD underlying refinancing, which amended the fixed rate on the debt streams to 5.598% (**GD-1**) and 5.643% (**GD-2**). Following the maturity of the GD-1 and GD-2 interest rate swaps on September 16, 2013, these debt issues reverted to floating rate debt at a coupon rate of 3 month BA + 0.253% until the September 5, 2018 maturity date.

2013/14 Total long term financings for the year were CAD $1,951.7 million, made up of:

- $1,195.4 million for new borrowing requirements.
- $250.4 million to refinance maturing debt.
- $505.9 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year, per quarter, were as follows:

Quarter 1 On April 2, 2013, Manitoba Hydro secured long term debt series GE for USD $400 million (CAD equivalent $405.9 million) and a June 1, 2018 maturity date. The debt, which was swapped to floating rate debt, was issued to refinance debt series FO-1 (USD $150 million), FO-2 (USD $203.1 million) and FO-3 (USD $46.9 million). Forward fixed interest rate swaps that were previously linked to debt series FO-1, FO-2 and FO-3 were re-linked to the GE underlying refinancing, which amended the fixed rate on the debt streams to 5.853% (**GE-1**), 6.901% (**GE-2**) and 6.901% (**GE-3**).

On June 10, 2013, Manitoba Hydro secured long term debt series **C137** for CAD $50 million and a March 5, 2063 maturity date. C137 was issued at a discount with proceeds of $49.5 million (net of commissions), a fixed rate coupon of 3.450%, and an all-in yield of 3.496%. The debt was issued to finance new borrowing requirements.

On June 15, 2013, Manitoba Hydro secured **HydroBonds Series 12** for new borrowing requirements. Estate redemptions are processed on all HydroBonds as necessary and the floating rate HydroBonds are subject to redemptions on an annual basis. HydroBonds were issued at par with proceeds of $128.3 million (net of commissions) as follows:

5 Year Floating Rate, June 15, 2018 maturity date	$124.4 million
3 Year Fixed Rate, June 15, 2016 maturity date	$ 3.1 million
5 Year Fixed Rate, June 15, 2018 maturity date	$ 0.7 million

Quarter 2 On July 29, 2013, Manitoba Hydro secured long term debt series **C129-2** for CAD $55 million and a September 5, 2052 maturity date. C129-2 was issued at a discount with proceeds of $46.6 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.918%. The debt was issued to finance new borrowing requirements.

On July 30, 2013, Manitoba Hydro secured long term debt series **C137-2** for CAD $25 million and a March 5, 2063 maturity date. C137-2 was issued at a discount with proceeds of $22.6 million (net of commissions), a fixed rate coupon of 3.450%, and an all-in yield of 3.887%. The debt was issued to finance new borrowing requirements.

On September 18, 2013, Manitoba Hydro secured long term debt series **GA-2** for CAD $250 million and a March 5, 2043 maturity date. GA-2 was issued at a discount with proceeds of $210.1 million (net of commissions), a fixed rate coupon of 3.350%, and an all-in yield of 4.311%. The debt was issued to finance new borrowing requirements.

On September 30, 2013, Manitoba Hydro secured long term debt series **C137-3** for CAD $37 million and a March 5, 2063 maturity date. C137-3 was issued at a discount with proceeds of $32.5 million (net of commissions), a fixed rate coupon of 3.450%, and an all-in yield of 4.019%. The debt was issued to finance new borrowing requirements.

Quarter 3 On October 10, 2013, Manitoba Hydro secured long term debt series **GG** for CAD $300 million and a September 5, 2045 maturity date. GG was issued at a discount with proceeds of $297.6 million (net of commissions), a fixed rate coupon of 4.050%, and an all-in yield of 4.096%. The debt was issued to finance new borrowing requirements.

On November 26, 2013, Manitoba Hydro secured long term debt series **GF** for CAD $300 million and a June 2, 2023 maturity date. GF was issued at a discount with proceeds of $279.5 million (net of commissions), a fixed rate coupon of 2.550%, and an all-in yield of 3.398%. The first $49.6 million of the debt was issued to finance new borrowing requirements. The residual $250.4 million was issued to refinance debt series EZ-3 ($174.6 million), HydroBonds ($60.9 million), 5B ($6.9 million), 3W ($1 million), 3X ($5 million), and 3Y ($2 million).

On November 29, 2013, Manitoba Hydro secured long term debt series **C135** for CAD $100 million and an April 2, 2019 maturity date. The debt, which was a floating rate note, was issued to refinance debt series EZ-2 ($54 million) and

EZ-5 ($46 million). Forward fixed interest rate swaps that were previously linked to debt series EZ-2 and EZ-5 were re-linked to the C135 underlying refinancing which amended the fixed rate on the debt stream to 4.801%.

On December 6, 2013, Manitoba Hydro secured long term debt series **C129-3** for CAD $50 million and a September 5, 2052 maturity date. C129-3 was issued at a discount with proceeds of $41.1 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 4.065%. The debt was issued to finance new borrowing requirements.

On December 17, 2013, Manitoba Hydro secured long term debt series **C129-4** for CAD $50 million and a September 5, 2052 maturity date. C129-4 was issued at a discount with proceeds of $40.8 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 4.099%. The debt was issued to finance new borrowing requirements.

On December 23, 2013, Manitoba Hydro secured long term debt series **C129-5** for CAD $50 million and a September 5, 2052 maturity date. C129-5 was issued at a discount with proceeds of $40.9 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 4.087%. The debt was issued to finance new borrowing requirements.

Quarter 4 On February 12, 2014, Manitoba Hydro secured long term debt series **C129-6** for CAD $50 million and a September 5, 2052 maturity date. C129-6 was issued at a discount with proceeds of $42.5 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.906%. The debt was issued to finance new borrowing requirements.

On February 18, 2014, Manitoba Hydro secured long term debt series **C129-7** for CAD $20 million and a September 5, 2052 maturity date. C129-7 was issued at a discount with proceeds of $17.0 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.915%. The debt was issued to finance new borrowing requirements.

On February 19, 2014, Manitoba Hydro secured long term debt series **C129-8** for CAD $20 million and a September 5, 2052 maturity date. C129-8 was issued at a discount with proceeds of $17.0 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.895%. The debt was issued to finance new borrowing requirements.

On February 20, 2014, Manitoba Hydro secured long term debt series **C137-4** for CAD $60 million and a March 5, 2063 maturity date. C137-4 was issued at a discount with proceeds of $54.5 million (net of commissions), a fixed rate coupon of 3.450%, and an all-in yield of 3.868%. The debt was issued to finance new borrowing requirements.

2014/15 Total long term financings for the year to date are CAD $2,072.6, made up of:

- $1,108.5 million for new borrowing requirements.
- $583.1 million to refinance maturing long term debt.
- $381.0 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year, per quarter, were as follows:

Quarter 1 On April 10, 2014, Manitoba Hydro secured long term debt series **C136** for CAD $50 million and a September 5, 2029 maturity date. The debt, which was swapped to floating rate debt, was issued to partially refinance debt series FS-2C ($100 million). A forward fixed interest rate swap that was previously linked to debt issue FS-2C was re-linked to the C136 underlying refinancing, which amended the fixed rate on $50 million of the debt stream to 5.020%.

On April 14, 2014, Manitoba Hydro secured long term debt series **C136-2** for CAD $50 million and a September 5, 2029 maturity date. The debt, which was swapped to floating rate debt, was issued to partially refinance debt series FS-2C ($100 million). A forward fixed interest rate swap that was previously linked to debt series FS-2C was re-linked to the C136-2 underlying refinancing, which amended the fixed rate on $50 million of the debt stream to 4.882%.

On April 14, 2014, Manitoba Hydro secured long term debt series **C129-9** for CAD $60 million and a September 5, 2052 maturity date. C129-9 was issued at a discount with proceeds of $51.5 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.858%. The debt was issued to finance new borrowing requirements.

On April 14, 2014, Manitoba Hydro secured long term debt series C138 for CAD $200 million and a May 15, 2020 maturity date. The debt, which was a floating rate note, was issued to refinance debt series FS-2A ($100 million) and FS-2B ($100 million). Forward fixed interest rate swaps that were previously linked to debt series FS-2A and FS-2B were re-linked to the C138 underlying refinancing, which amended the fixed rate on the debt streams to 7.312% (**C138-A**) and 7.443% (**C138-B**).

On April 15, 2014, Manitoba Hydro secured long term debt series **C136-3** for CAD $31 million and a September 5, 2029 maturity date. The debt, which was swapped to floating rate debt, was issued to partially refinance debt series FS-2D ($81 million). A forward fixed interest rate swap that was previously linked to debt series FS-2D was re-linked to the C136-3 underlying refinancing, which amended the fixed rate on $31 million of the debt stream to 5.058%.

On April 23, 2014, Manitoba Hydro secured long term debt series **C129-10** for CAD $50 million and a September 5, 2052 maturity date. C129-10 was issued at a discount with proceeds of $43.6 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.786%. The debt was issued to finance new borrowing requirements.

On April 30, 2014, Manitoba Hydro secured long term debt series **GG-2** for CAD $250 million and a September 5, 2045 maturity date. GG-2 was issued at a premium with proceeds of $260.5 million (net of commissions), a fixed rate coupon of 4.050%, and an all-in yield of 3.819%. The debt was issued to finance new borrowing requirements.

On May 5, 2014, Manitoba Hydro secured long term debt series **C138-2** for CAD $50 million and a May 15, 2020 maturity date. The debt, which was a floating rate note, was issued to partially refinance debt series FS-2D ($81 million). A forward fixed interest rate swap that was previously linked to debt series FS-2D was re-linked to the C138-2 underlying refinancing, which amended the fixed rate on $50 million of the debt stream to 4.897%.

On June 9, 2014, Manitoba Hydro secured long term debt series **C129-11** for CAD $25 million and a September 5, 2052 maturity date. C129-11 was issued at a discount with proceeds of $22.2 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.702%. The debt was issued to finance new borrowing requirements.

On June 10, 2014, Manitoba Hydro secured long term debt series **C129-12** for CAD $40 million and a September 5, 2052 maturity date. C129-12 was issued at a discount with proceeds of $35.5 million (net of commissions), a fixed rate coupon of 3.150%, and an all-in yield of 3.699%. The debt was issued to finance new borrowing requirements.

On June 24, 2014, Manitoba Hydro secured long term debt series **C139** for CAD $50 million and a September 5, 2054 maturity date. C139 was issued at a discount with proceeds of $49.8 million (net of commissions), a fixed rate coupon of 3.650%, and an all-in yield of 3.666%. The debt was issued to finance new borrowing requirements.

Quarter 2 On July 11, 2014, Manitoba Hydro secured long term debt series **C139-2** for CAD $25 million and a September 5, 2054 maturity date. C139-2 was issued at a premium with proceeds of $25.1 million (net of commissions), a fixed rate coupon of 3.650%, and an all-in yield of 3.625%. The debt was issued to refinance HydroBonds.

On September 1, 2014, existing floating rate debt series FA for $150 million and a March 3, 2037 maturity date was linked to forward fixed interest rate swaps that were previously linked to maturing debt series FM-1 ($25 million), FM-2 ($75 million) and FM-3 ($50 million). Debt series FA, as an underlying debt issue, reduced the fixed rate on the FM swap streams by 0.423% to the swap maturity date of September 1, 2029. The amended fixed rates are 6.211% (**FA-1**), 6.311% (**FA-2**) and 6.266% (**FA-3**).

On September 3, 2014, Manitoba Hydro secured long term debt series **C140** for AUD $100 million and a March 3, 2025 maturity date. The issue was swapped to CAD $101.6 million and a fixed rate coupon of 2.916%. The debt was issued to refinance $101.6 million of maturing debt series FM (FM-1, FM-2, FM-3 and FM-4 totaling $250 million).

On September 5, 2014, Manitoba Hydro secured long term debt series **GH** for CAD $300 million and a June 2, 2024 maturity date. GH was issued at a premium with proceeds of $312.1 million (net of commissions), a fixed rate coupon of 3.300%, and an all-in yield of 2.825%. The debt was issued to refinance $148.4 million of debt series FM (FM-1, FM-2, FM-3 and FM-4 totaling

$250 million), $68.1 million of HydroBonds, as well as to finance $83.5 million of new borrowing requirements.

On September 23, 2014, Manitoba Hydro secured long term debt series **GG-3** for CAD $300 million and a September 5, 2045 maturity date. GG-3 was issued at a premium with proceeds of $322.6 million (net of commissions), a fixed rate coupon of 4.050%, and an all-in yield of 3.642%. The debt was issued to finance new borrowing requirements.

Quarter 3 On November 20, 2014, Manitoba Hydro secured long term debt series **GG-4** for CAD $400 million and a September 5, 2045 maturity date. GG-4 was issued at a premium with proceeds of $434.2 million (net of commissions), a fixed rate coupon of 4.050%, and an all-in yield of 3.589%. The debt was issued to refinance maturing debt series FC-3 ($200 million) as well as to finance new borrowing requirements ($200 million).

On November 25, 2014, Manitoba Hydro executed a currency swap to convert USD $200 million of principal for debt series **EE** to CAD $228.4 million. The fixed coupon rate on EE remains at 9.500% on USD $200 million.

On December 3, 2014, existing floating rate debt series **CO77-2** for $100 million and **CO77-3** for $50 million, each with a February 11, 2020 maturity date, were linked to a forward fixed interest rate swap that was previously linked to debt series FC-3 ($200 million). Debt series CO77-2 and CO77-3, as underlying debt issues, reduced the fixed rate on $150 million of the FC-3 swap stream by 0.221% to the swap maturity date of June 2, 2018. The amended fixed rate for both CO77-2 and CO77-3 is 6.927%.

On December 3, 2014, existing floating rate debt series **CO68** for $50 million and a March 5, 2044 maturity date was linked to a forward fixed interest rate swap that was previously linked to maturing debt series FC-3 ($200 million). Debt series CO68, as an underlying debt issue, reduced the fixed rate on $50 million of the FC-3 swap stream by 0.111% to the swap maturity date of June 2, 2018. The amended fixed rate for CO68 is 7.037%

On December 4, 2014, Manitoba Hydro secured long term debt series **C137-5** for CAD $50 million and a March 5, 2063 maturity date. C137-5 was issued at a premium with proceeds of $51.1 million (net of commissions), a fixed rate coupon of 3.450%, and an all-in yield of 3.354%. The debt was issued to finance new borrowing requirements.

On December 31, 2014, Manitoba Hydro secured mitigation bond **5C-1** for CAD $10 million and a December 31, 2024 maturity date. 5C-1 was issued at par, a fixed rate coupon, and all-in yield of 3.723%. The debt was issued to refinance $10 million of maturing mitigation bond 5A ($40 million).

On December 31, 2014, Manitoba Hydro secured mitigation bond **5C-2** for CAD $10 million and a December 31, 2029 maturity date. 5C-2 was issued at par, a fixed rate coupon, and all-in yield of 4.049%. The debt was issued to refinance $10 million of maturing mitigation bond 5A ($40 million).

On December 31, 2014, Manitoba Hydro secured mitigation bond **5C-3** for CAD $10 million and a December 31, 2034 maturity date. 5C-3 was issued at par, a fixed rate coupon, and all-in yield of 4.245%. The debt was issued to refinance $10 million of maturing mitigation bond 5A ($40 million).

On December 31, 2014, Manitoba Hydro secured mitigation bond **5C-4** for CAD $10 million and a December 31, 2039 maturity date. 5C-4 was issued at par, a fixed rate coupon, and all-in yield of 4.311%. The debt was issued to refinance $10 million of maturing mitigation bond 5A ($40 million).

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A schedule detailing the maturities of MH's current long-term debt issues.

Please see the following long term debt maturity schedule as at December 31, 2014 for each debt series, identifying the currency for both interest and principal payments. This schedule excludes short term debt, which by definition have a term to maturity of less than one year.

The Maturity Dates in the third column from the left conform to the Corporation’s financial statement presentation, which in accordance with accounting standards specify the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates).

The Action Dates in the fourth column from the left identify the maturities of the the physical debt. Therefore in cases where the maturity of underlying physical debt is before the linked forward interest rate swap for a debt series, a refinancing of the underlying physical debt will be required on the date highlighted in brown on the schedule.

The coupon rates (rounded to three decimal places for this schedule) identify the gross interest rates for each debt issue in its specified currency. The yield rates (rounded to three decimal places) conform to the Corporation’s financial statement presentation, which in accordance with accounting standards show the effective all-in interest rate over the entire term of the debt issue (converted to Canadian dollars {CAD} where applicable). As floating rate debt will be subject to periodic interest rate resetting, the yield rate calculation for floating rate debt combines actual interest rates to the balance sheet date plus forecasted interest rates for the reminder of the time to the maturity date (utilizing the Corporation’s forecasted interest rates for the variable component of the coupon payments).

The principal amounts are shown at par, with US dollar debt principal translated to CAD using the USD/CAD exchange rate on the balance sheet date.

MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At December 31, 2014
(in millions $; with USD/CAD of 1.1601 at December 31, 2014)

Underlying physical debt matures before linked swap

Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
C115	CAD/ CAD	05/04/15	05/04/15	3 BA + 0.230 %	1.494 %	50.0		50.0
4K	CAD/ CAD	05/12/15	05/12/15	9.125 %	9.125 %	12.0		12.0
EY2	CAD/ CAD	12/03/15	12/03/15	3 BA + 0.046 %	2.263 %	50.0		50.0
EY	CAD/ CAD	12/03/15	12/03/15	3 BA + 0.053 %	4.927 %	200.0		200.0
C121-3	CAD/ CAD	04/19/16	04/19/16	3 BA + 0.200 %	1.481 %	100.0		100.0
HB11-5FX	CAD/ CAD	06/15/16	06/15/16	2.750 %	2.961 %	7.3		7.3
HB11-5FL	CAD/ CAD	06/15/16	06/15/16	1.750 %	1.828 %	22.6		22.6
HB12-3FX	CAD/ CAD	06/15/16	06/15/16	1.650 %	1.891 %	3.2		3.2
AZ	CAD/ CAD	07/17/16	07/17/16	3 BA + 1.080 %	4.205 %	200.6		200.6
C-011	CAD/ CAD	09/22/17	09/22/17	7.525 %	7.490 %	55.5		55.5
4L	CAD/ CAD	11/17/17	11/17/17	6.250 %	6.250 %	20.0		20.0
BM	CAD/ CAD	01/15/18	01/15/18	3 BA + 3.290 %	6.660 %	255.0		255.0
C132	CAD/ CAD	04/02/18	04/02/18	7.515 %	6.891 %	200.0		200.0
HB12-5FX	CAD/ CAD	06/15/18	06/15/18	1.750 %	1.940 %	0.7		0.7
HB12-5FL	CAD/ CAD	06/15/18	06/15/18	1.750 %	2.326 %	42.0		42.0
GD	CAD/ CAD	09/05/18	09/05/18	1.850 %	1.954 %	100.0		100.0
GD-1	CAD/ CAD	09/05/18	09/05/18	3 BA + 0.253 %	2.753 %	100.0		100.0
GD-2	CAD/ CAD	09/05/18	09/05/18	3 BA + 0.253 %	2.757 %	100.0		100.0
EE	USD/ CAD	09/15/18	09/15/18	9.500 %	10.000 %	228.4		228.4
BU	USD/ USD	12/01/18	12/01/18	9.625 %	10.411 %		200.0	232.0
3V	CAD/ CAD	12/30/18	12/30/18	10.000 %	10.000 %	3.5		3.5
3W	CAD/ CAD	12/30/18	12/30/18	10.000 %	10.000 %	1.0		1.0
CO77-2	CAD/ CAD	02/11/20	02/11/20	6.927 %	4.859 %	100.0		100.0
CO77-3	CAD/ CAD	02/11/20	02/11/20	6.927 %	3.294 %	50.0		50.0
GE-1	USD/ USD	03/15/20	06/01/18	5.853 %	7.299 %		150.0	174.0
C138-A	CAD/ CAD	05/15/20	05/15/20	7.312 %	5.086 %	100.0		100.0
C138-B	CAD/ CAD	05/15/20	05/15/20	7.443 %	5.167 %	100.0		100.0
FP-2	CAD/ CAD	06/03/20	06/03/20	4.150 %	4.244 %	125.0		125.0
FP-3	CAD/ CAD	06/03/20	06/03/20	4.150 %	3.469 %	250.0		250.0
GE-2	USD/ USD	10/02/20	06/01/18	6.901 %	8.351 %		203.1	235.6
GE-3	USD/ USD	10/02/20	06/01/18	6.901 %	8.351 %		47.0	54.5
CO	USD/ USD	09/15/21	09/15/21	8.875 %	10.275 %		300.0	348.0
4A	CAD/ CAD	12/31/21	12/31/21	9.100 %	9.100 %	3.5		3.5
FH-1	USD/ USD	02/01/22	12/06/16	6.405 %	5.934 %		250.0	290.0
FH-2	USD/ USD	02/01/22	12/06/16	6.406 %	5.923 %		100.0	116.0
GC	CAD/ CAD	09/06/22	09/06/22	3 BA + 0.499 %	3.286 %	296.4		296.4
FH-3	USD/ USD	09/16/22	12/06/16	6 LIBOR + 0.130 %	2.226 %		150.0	174.0
GF	CAD/ CAD	06/02/23	06/02/23	2.550 %	3.398 %	300.0		300.0
GH	CAD/ CAD	06/02/24	06/02/24	3.300 %	2.825 %	300.0		300.0
5C-1	CAD/ CAD	12/31/24	12/31/24	3.723 %	3.723 %	10.0		10.0
C140	CAD/ CAD	03/03/25	03/03/25	2.916 %	2.916 %	101.6		101.6
C119-2	CAD/ CAD	09/05/25	09/05/25	3 BA + 0.425 %	3.104 %	150.0		150.0
DT	CAD/ CAD	12/22/25	12/22/25	7.750 %	7.952 %	170.0		170.0
DT-2	USD/ CAD	12/22/25	12/22/25	7.750 %	7.168 %	130.0		130.0
4N	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
4M	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
C119-1	CAD/ CAD	09/01/29	09/05/25	6.575 %	6.575 %	100.0		100.0
5C-2	CAD/ CAD	12/31/29	12/31/29	4.049 %	4.049 %	10.0		10.0
CL	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.796 %	300.0		300.0
CLW	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.581 %	299.9		299.9
C116	CAD/ CAD	03/05/31	03/05/31	6.300 %	4.650 %	100.0		100.0
4B	CAD/ CAD	04/01/31	04/01/31	5.840 %	7.612 %	3.8		3.8
4C	CAD/ CAD	04/01/31	04/01/31	5.840 %	5.840 %	1.4		1.4
4Y	CAD/ CAD	05/01/31	05/01/31	5.650 %	7.436 %	4.6		4.6
CO52	CAD/ CAD	10/29/32	10/29/32	6.300 %	5.730 %	30.0		30.0
5C-3	CAD/ CAD	12/31/34	12/31/34	4.245 %	4.245 %	10.0		10.0
FP-1	CAD/ CAD	04/12/35	06/03/20	5.754 %	5.196 %	175.0		175.0
C135	CAD/ CAD	12/03/35	04/02/19	4.801 %	4.801 %	100.0		100.0
FA-1	CAD/ CAD	03/05/37	03/05/37	6.211 %	5.175 %	25.0		25.0
FA-2	CAD/ CAD	03/05/37	03/05/37	6.311 %	5.213 %	75.0		75.0
FA-3	CAD/ CAD	03/05/37	03/05/37	6.266 %	5.196 %	50.0		50.0
FA-4	CAD/ CAD	03/05/37	03/05/37	4.505 %	4.505 %	50.0		50.0
FJ	CAD/ CAD	09/12/37	09/22/17	5.104 %	5.104 %	250.0		250.0

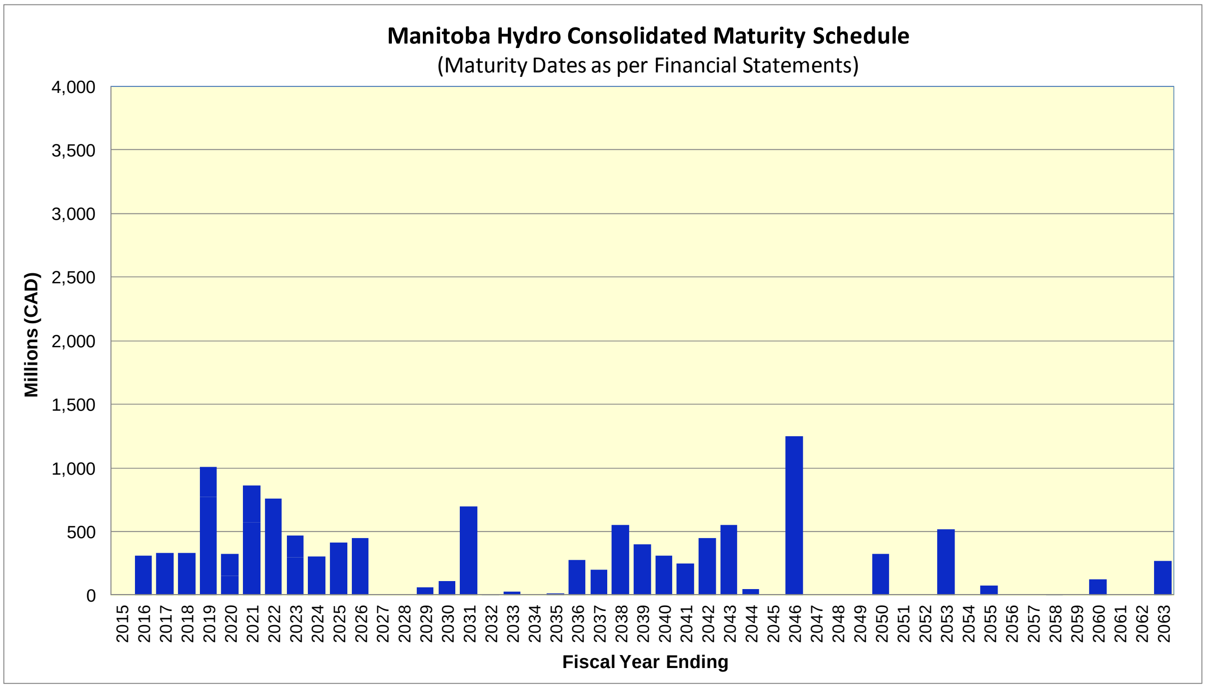
MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At December 31, 2014
(in millions $; with USD/CAD of 1.1601 at December 31, 2014)

Underlying physical debt matures before linked swap

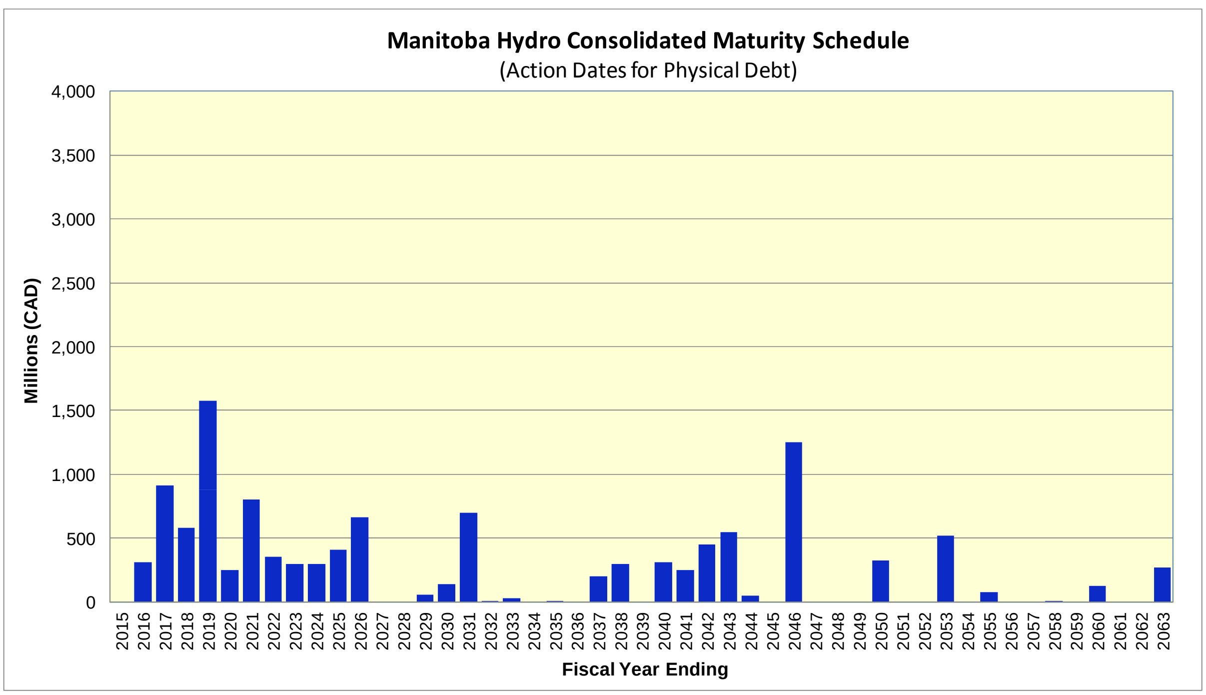
Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
PB-2	CAD/ CAD	03/05/38	03/05/38	4.600 %	4.759 %	300.0		300.0
C132-2A	CAD/ CAD	11/01/38	04/02/18	4.997 %	4.997 %	85.0		85.0
C132-2B	CAD/ CAD	11/01/38	04/02/18	4.927 %	4.927 %	19.0		19.0
C136-3	CAD/ CAD	11/01/38	09/05/29	5.058 %	5.058 %	31.0		31.0
C138-2	CAD/ CAD	11/01/38	05/15/20	4.897 %	4.897 %	50.0		50.0
C119-3C	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	15.0		15.0
C119-3A	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	50.0		50.0
C119-3B	CAD/ CAD	12/01/38	09/05/25	5.232 %	5.232 %	50.0		50.0
C136	CAD/ CAD	03/01/39	09/05/29	5.020 %	5.020 %	50.0		50.0
C136-2	CAD/ CAD	03/01/39	09/05/29	4.882 %	4.882 %	50.0		50.0
5C-4	CAD/ CAD	12/31/39	12/31/39	4.311 %	4.311 %	10.0		10.0
FK-2	CAD/ CAD	03/05/40	03/05/40	4.650 %	5.174 %	300.0		300.0
FR-2	CAD/ CAD	03/05/41	03/05/41	4.100 %	4.599 %	250.0		250.0
CO40	CAD/ CAD	03/05/42	03/05/42	3 BA + 0.179 %	3.604 %	50.0		50.0
FT	CAD/ CAD	03/05/42	03/05/42	4.492 %	4.492 %	400.0		400.0
GA	CAD/ CAD	03/05/43	03/05/43	3.350 %	3.413 %	300.0		300.0
GA-2	CAD/ CAD	03/05/43	03/05/43	3.350 %	4.311 %	250.0		250.0
CO68	CAD/ CAD	03/05/44	03/05/44	7.037 %	4.596 %	50.0		50.0
GG	CAD/ CAD	09/05/45	09/05/45	4.050 %	4.096 %	300.0		300.0
GG-2	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.819 %	250.0		250.0
GG-3	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.642 %	300.0		300.0
GG-4	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.589 %	400.0		400.0
FN	CAD/ CAD	03/05/50	03/05/50	4.700 %	4.726 %	200.0		200.0
FN-2	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.629 %	75.0		75.0
FN-3	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.281 %	50.0		50.0
C129	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.178 %	50.0		50.0
C129-2	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.918 %	55.0		55.0
C129-3	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.065 %	50.0		50.0
C129-4	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.099 %	50.0		50.0
C129-5	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.087 %	50.0		50.0
C129-6	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.906 %	50.0		50.0
C129-7	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.915 %	20.0		20.0
C129-8	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.895 %	20.0		20.0
C129-9	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.858 %	60.0		60.0
C129-10	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.786 %	50.0		50.0
C129-11	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.702 %	25.0		25.0
C129-12	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.699 %	40.0		40.0
C139	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.666 %	50.0		50.0
C139-2	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.625 %	25.0		25.0
4Z	CAD/ CAD	06/09/57	06/09/57	7.100 %	7.100 %	7.0		7.0
C110	CAD/ CAD	03/05/60	03/05/60	5.200 %	4.629 %	125.0		125.0
C109	CAD/ CAD	03/05/63	03/05/63	4.625 %	4.638 %	50.0		50.0
C137	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.496 %	50.0		50.0
C137-2	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.887 %	25.0		25.0
C137-3	CAD/ CAD	03/05/63	03/05/63	3.450 %	4.019 %	37.0		37.0
C137-4	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.868 %	60.0		60.0
C137-5	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.354 %	50.0		50.0
Total Long Term Debt						**10,466.9**	**1,400.0**	**12,091.0**

Note that some of the long term debt issues may be retired at their maturity. Manitoba Hydro will consider the availability of sinking fund withdrawals and surplus cash to reduce the required refinancing of maturing debt.

The Corporation’s interest rate risk policy and guidelines consider debt maturities on a 12 month forward basis. For ease of comparison, the following chart depicts the volume of financial statement debt maturities (“Maturity Dates”) within each fiscal year.



The following chart depicts the volume of physical debt maturities (“Action Dates”) within each fiscal year. As noted by DBRS on page 6 of their October 23, 2014 report on the Manitoba Hydro-Electric Board (see Appendix 3.8): “Manitoba Hydro maintains a relatively smooth maturity profile with potential volatility from foreign currency debt mostly mitigated through natural and cash flow hedges, and a moderate level of floating-rate debt (19% of floating-rate debt and 7% of long-term debt to be refinanced within a year), which adds stability to debt servicing costs and minimizes interest rate risk.”



Finance Expense-Debt Levels MFR 8

A schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions of debt maturing in 10 years, 20 years and greater than 20 years.

The following schedule provides the principal amount of debt outstanding at fiscal year end, as well as the relative proportion of debt maturing within specific time frames and the weighted average term to maturity of the total long term debt portfolio. Actuals were provided at March 31 for the fiscal years ended 2004 – 2014, with IFF14 forecasted year end figures to March 31, 2017.

Note that the schedule was prepared using debt maturities conforming to the Corporation's financial statement presentation, which in accordance with accounting standards specify the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates). Also note that the forecasted debt percentages and weighted average terms to maturity will be affected by the simplying forecast modeling assumption of a 20 year term to maturity for all new debt issuance. For example, this forecast assumption leads to a disproportionate forecasted percentage of the debt portfolio being shown as maturing between 10 – 20 years from the depicted fiscal year end. Actual terms to maturity for new debt issuance will vary from forecast, and the distribution of the future transacted debt issuance will continue to have a combination of short, medium and long term maturities. See the Debt Management Strategy in Appendix 3.7 for additional information regarding the Corporation's debt financing requirements and strategies.

MANITOBA HYDRO

Finance Expense - Debt Levels MFR 8

Actuals are shown for March 31, 2004 - 2014; with forecast information shown for March 31, 2015 - 2017.
($ in CAD millions)

	Debt Maturing Less than 10 Years		Debt Maturing Between 10 - 20 Years		Debt Maturing Greater than 20 Years		Total Long Term Debt	Weighted Average Term to Maturity
	$	% of Total	$	% of Total	$	% of Total	$	(Years)
March 31, 2004	2,586	35.1 %	3,521	47.7 %	1,268	17.2 %	7,375	13.8
March 31, 2005	2,377	33.1 %	3,346	46.5 %	1,468	20.4 %	7,191	13.8
March 31, 2006	2,397	33.5 %	3,317	46.3 %	1,443	20.2 %	7,158	13.7
March 31, 2007	2,623	36.3 %	3,094	42.9 %	1,501	20.8 %	7,218	12.9
March 31, 2008	2,996	39.5 %	2,513	33.1 %	2,081	27.4 %	7,590	13.5
March 31, 2009	3,763	45.8 %	2,026	24.7 %	2,421	29.5 %	8,209	13.6
March 31, 2010	3,963	46.0 %	1,805	21.0 %	2,846	33.0 %	8,614	14.8
March 31, 2011	3,967	45.6 %	2,241	25.7 %	2,496	28.7 %	8,704	15.3
March 31, 2012	4,841	51.4 %	1,619	17.2 %	2,962	31.4 %	9,422	14.9
March 31, 2013	5,179	51.7 %	1,499	15.0 %	3,332	33.3 %	10,010	14.8
March 31, 2014	5,160	46.9 %	1,500	13.6 %	4,349	39.5 %	11,009	16.2
March 31, 2015 *	5,028	41.4 %	1,520	12.5 %	5,609	46.1 %	12,157	17.6
March 31, 2016 *	5,194	36.4 %	3,745	26.2 %	5,334	37.4 %	14,273	17.4
March 31, 2017 *	4,860	28.4 %	7,145	41.7 %	5,134	30.0 %	17,139	17.3

* The forecasted debt percentages and weighted average terms to maturity will be affected by the simplifying modeling assumption of a 20 year term to maturity for all new debt issuance. Actual terms to maturity will vary from forecast.

DSM MFR 1

A continuity schedule showing spending, amortization expense, amortization rates and balances for demand side management for the years 2004/05 through the test years.

Please see the following schedule.

MANITOBA HYDRO
DSM CONTINUITY SCHEDULE

Fiscal Year	Beginning Balance	additions	amortization	transfer	Adjustment *	DSM** Deferral	Ending Balance	Rate
Actual 2004/05	$ 61 187 195	21 153 356	(6 019 759)				76 320 792	6.7%
Actual 2005/06	$ 76 320 792	26 780 871	(7 355 047)				95 746 616	6.7%
Actual 2006/07	$ 95 746 616	36 561 025	(9 099 268)	(432 717)			122 775 656	6.7%
Actual 2007/08	$ 122 775 656	37 773 794	(11 357 463)	(664 968)			148 527 019	6.7%
Actual 2008/09	148 527 019	35 630 172	(20 022 389)	(452 011)			163 682 791	10%
Actual 2009/10	163 682 791	31 596 457	(22 063 927)	(47 627)	(4 634 995)		168 532 699	10%
Actual 20010/11	168 532 699	28 506 968	(23 994 359)	(110 072)	(237 294)		172 697 942	10%
Actual 2011/12	172 697 942	27 461 523	(26 190 555)	(144 628)			173 824 281	10%
Actual 2012/13	173 824 281	27 619 555	(28 217 076)	(1 030 101)			172 196 660	10%
Actual 2013/14	172 196 660	26 324 718	(30 262 163)	(175 351)		16 300 000	184 383 864	10%
Forecast 2014/15	184 383 864	51 780 061	(31 576 103)				204 587 821	10%
Forecast 2015/16	204 587 821	59 158 197	(34 957 276)				228 788 743	10%
Forecast 2016/17	228 788 743	76 596 062	(37 501 478)				267 883 327	10%

* The adjustment is a result of the change in accounting standard section 3064 and the removal of ineligible costs related to research and promotions.

** As a result of a directive by the PUB in board order 43/13, Manitoba Hydro established a deferral account equal to the difference between amounts budgeted in the 2011 Power Smart report and the actual level of spending.

DSM MFR 2

An update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs, including a continuity schedule of program spending since inception.

Please see below a description of projects supported through the Affordable Energy Fund.

- **Low-Income/Community-Based Initiative: $23.1 Million**
  This initiative targets low-income Manitobans, including Aboriginals and seniors. These funds would be incremental to incentives that are available through Manitoba Hydro's Power Smart programs.

- **Geothermal Support Program: $1.6 Million**
  This initiative supports the application of geothermal technology.

- **Community Energy Development: $7.8 Million**

  - ***Energy & Resource Fund - $750 000***
    This fund, managed by the First Peoples Economic Growth Fund, is a joint initiative between the Government of Manitoba and the Assembly of Manitoba Chiefs. The fund was created to maximize First Nations participation in Major Energy and Resource Projects.

  - ***ecoENERGY Program Funding - $4.1 Million***
    This initiative provides funding to support the cost of offering ecoENERGY audits in Manitoba at a reduced cost for customers.

  - ***Power Smart Residential Loan (Additional) - $350 000***
    This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost-recovery rate to a rate of 3.9%.

  - ***Electric Bus - $1.2 Million***
    This joint initiative among the Province of Manitoba, Manitoba Hydro, Red River Community College, New Flyer Industries and Mitsubishi Heavy Industries, provides funding to assist in developing a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

- ***Fort Whyte EcoVillage - $120 000***
  This initiative provides funding to support the research and design of a world-class EcoVillage located at Fort Whyte Alive.

- ***Diesel Community Green Pilot Demonstration - $400 000***
  This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

- ***Metis Generation Fund for Resource & Development - $500 000***
  This funding is to be managed by the Métis Economic Development Organization for the purposes outlined in Bill 11.

- ***Power Smart Pay As You Save (PAYS) Financing Program - $400 000***
  This initiative provides funding to reduce the interest rate for the Power Smart PAYS Financing Program from a cost-recovery rate to a rate of 3.9%.

- **Community Support and Outreach: $750 000**
  This initiative provides support for the participation of First Nation communities in the Lower Income Energy Efficiency Program through dedicated internal resources.

- **Oil and Propane-Heated Residential Homes: $250 000**
  This initiative extends the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas.

- **Special Projects: $4.6 Million (including accrued fund interest as of December 31, 2014)**

  - ***Residential Energy Assessment Service - $545 000***
    This initiative funds the incremental costs associated with delivering Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

  - ***Oil and Propane Furnace Replacement - $150 000***
    This initiative targets the replacement of oil and propane furnaces with either an electric or high efficient natural gas furnace. The program provides a rebate of $245 to participating customers. Low Income customers will be eligible to convert at a cost of $9.50 per month for five years.

- ***Residential Solar Water Heating Program - $305 000***
  This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

- ***Power Smart Residential Loan - $2.45 Million***
  This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 3.9%.

- ***Oil and Propane-Heated Residential Homes (Additional) - $300 000***
  This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity or natural gas.

- ***Spruce Wood Loggers - $175 000***
  This initiative provides funding to support Spruce Wood Loggers in upgrading their operations to include pelletized ground wood and waste sawdust material. The pellets would provide an alternative fuel for coal-fired boilers and potentially prevent some customer in close proximity to Spruce Wood Loggers from converting to electric boilers.

The table below provides information on Affordable Energy Fund program expenditures since inception.

Affordable Energy Fund ($millions)

	Actual Expenditures (millions)								Forecasted Expenditures (millions)				
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17*	2017/18 - 2026/27	Total
Low-Income/Community Based Initiative	0.3	0.2	0.9	1.7	2.7	3.1	3.3	3.0	4.0	3.7	1.0	-	23.9
Geothermal Support	0.6	0.3	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	1.6
Community Energy Development													
ecoENERGYProgram Funding	-	-	-	-	-	2.8	1.2	0.0	-	-	-	-	4.1
Power Smart PAYS Financing Program	-	-	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.4
Energy & Resource Fund	-	-	-	0.8	-	-	-	-	-	-	-	-	0.8
Manitoba Electric Bus	-	-	-	-	-	0.7	0.1	0.2	0.2	0.0	0.0	0.0	1.2
FortWhyte EcoVillage	-	-	-	-	-	0.1	-	-	-	-	-	-	0.1
Diesel Community Green Pilot Demonstration	-	-	-	-	-	-	-	-	0.4	-	-	-	0.4
Métis Generation Fund	-	-	-	-	-	-	-	0.5	-	-	-	-	0.5
Community Support and Outreach	-	-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	-	-	-	0.8
Oil and Propane Heated Homes	-	0.1	0.1	0.0	0.0	0.0	-	0.0	-	-	-	-	0.3
Special Projects													
Residential ecoEnergy Audits	-	0.1	0.2	0.1	0.1	0.0	-	-	-	-	-	-	0.5
Oil and Propane Furnace Replacement	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.2
Solar Water Heaters	-	-	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	-	-	-	0.1	0.3	0.4	0.5	0.5	0.4	0.2	0.1	0.0	2.5
Oil and Propane-Heated Residential Homes -	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3
Spruce Wood Loggers	-	-	-	-	-	-	-	-	0.2	-	-	-	0.2
ANNUAL EXPENDITURES	0.9	0.6	1.4	3.1	3.5	7.5	5.4	4.4	5.3	4.1	1.3	0.5	38.0

Note: Zeros indicate a small amount that rounds to zero.

* Assumes future reallocation of unused funds to support the Low-Income/Community Based Initiative as required.

Load Forecast and Power Smart Plans MFR 2

MFR #2:
File tabular 12SEP actual load profiles as per PCOSS14 Schedule D-2 for F2009 to F2014 separately depicting

- ***Domestic Load by subclass***
- ***Firm Exports (5x16)***
- ***Peak Opportunity Exports (5x16)***
- ***Weekend Exports (2x16)***
- ***Off-peak Exports (7x8)***

The export periods requested do not coincide with those defined in PCOSS Schedule D-2. Monthly export energy quantities for 5x16 (Firm and Opportunity), 2x16, and 7x8 are provided below.

	PHYSICAL EXPORTS			
Month	Firm 5x16 MWh	Opportunity 5x16 MWh	7x8 Off Peak MWh	2x16 Off Peak MWh
April,2009	247,441	173,704	172,744	118,688
May,2009	249,439	203,198	247,181	234,155
June,2009	295,739	256,481	228,694	198,391
July,2009	324,423	278,510	381,829	214,361
August,2009	298,305	255,476	373,763	270,941
September,2009	242,396	256,307	349,223	175,792
October,2009	266,656	297,951	397,827	236,277
November,2009	199,600	261,391	236,673	230,155
December,2009	214,020	93,996	38,191	85,206
January,2010	191,875	81,165	91,481	158,284
February,2010	199,186	80,320	67,180	98,586
March,2010	229,686	279,852	99,535	130,185
April,2010	214,238	285,142	123,765	145,536
May,2010	220,538	128,244	18,010	79,915
June,2010	317,232	210,047	159,861	154,214
July,2010	331,945	233,739	373,723	240,268
August,2010	343,313	253,771	421,478	245,600
September,2010	288,880	248,337	329,000	239,054
October,2010	246,139	289,612	368,516	264,660
November,2010	187,629	239,636	284,248	151,012
December,2010	182,986	123,996	144,931	117,730

	PHYSICAL EXPORTS			
Month	Firm 5x16 MWh	Opportunity 5x16 MWh	7x8 Off Peak MWh	2x16 Off Peak MWh
January,2011	139,327	82,504	115,329	106,516
February,2011	146,989	111,846	136,923	107,700
March,2011	197,252	187,520	235,804	137,403
April,2011	190,717	262,153	289,194	167,257
May,2011	210,187	315,910	329,731	225,110
June,2011	327,450	257,881	298,109	178,801
July,2011	317,517	221,195	481,614	309,100
August,2011	355,501	221,798	458,104	210,774
September,2011	281,434	164,531	283,470	172,219
October,2011	243,901	167,951	292,861	198,222
November,2011	231,580	137,362	158,754	150,180
December,2011	186,983	64,425	94,460	108,449
January,2012	175,171	82,760	98,717	117,438
February,2012	223,316	63,105	46,590	62,166
March,2012	248,517	172,552	50,066	74,157
April,2012	218,411	158,597	41,556	109,967
May,2012	246,100	303,712	93,525	161,585
June,2012	300,115	229,457	167,098	193,053
July,2012	317,841	221,497	427,196	271,521
August,2012	351,227	288,425	449,862	247,269
September,2012	255,959	245,900	330,288	280,249
October,2012	254,332	238,871	76,201	116,375
November,2012	213,131	132,848	90,320	110,420
December,2012	179,849	66,086	51,742	74,930

	PHYSICAL EXPORTS			
Month	Firm 5x16 MWh	Opportunity 5x16 MWh	7x8 Off Peak MWh	2x16 Off Peak MWh
January,2013	227,501	70,064	48,122	72,582
February,2013	217,018	100,946	48,489	79,753
March,2013	234,300	172,746	100,807	180,551
April,2013	238,830	187,420	129,353	137,507
May,2013	246,094	345,591	301,445	248,998
June,2013	279,960	300,673	382,078	286,912
July,2013	350,523	291,917	473,118	271,511
August,2013	340,626	328,441	505,447	291,604
September,2013	199,119	219,359	329,875	283,987
October,2013	257,206	327,709	384,418	204,372
November,2013	194,837	155,334	174,593	134,096
December,2013	177,226	52,294	42,573	70,585
January,2014	200,679	61,800	52,577	47,239
February,2014	175,743	71,238	52,829	48,328
March,2014	204,615	154,532	90,616	114,685
April,2014	238,102	197,571	162,553	163,112
May,2014	189,237	216,554	272,777	200,454
June,2014	293,121	296,744	400,971	235,720
July,2014	331,020	283,944	465,748	264,424
August,2014	328,412	247,654	485,412	292,302
September,2014	266,341	225,945	330,645	195,576
October,2014	151,279	66,269	140,324	71,435
November,2014	167,034	149,949	183,274	143,455
December,2014	193,363	132,303	142,749	139,614

The Table below provides total domestic load for each fiscal year.

Fiscal Year	Revenue Class	Spring 04/01 to 05/31			Summer 06/01 to 09/30			Fall 10/01 to 11/30			Winter 12/01 to 03/31			Total Energy
		On Peak MTWRF 07:01 - 11:00, 16:01 - 20:00	Mid Peak MTWRF 11:01 - 16:00, 20:01 - 23:00 SA, SU, Holidays 07:01 - 23:00	Off Peak Every Day 23:01 - 07:00	On Peak MTWRF 12:01 - 20:00	Mid Peak MTWRF 07:01 - 12:00, 20:01 - 23:00 SA, SU, Holidays 07:01 - 23:00	Off Peak Every Day 23:01 - 07:00	On Peak MTWRF 07:01 - 11:00, 16:01 - 20:00	Mid Peak MTWRF 11:01 - 16:00, 20:01 - 23:00 SA, SU, Holidays 07:01 - 23:00	Off Peak Every Day 23:01 - 07:00	On Peak MTWRF 07:01 - 11:00, 16:01 - 20:00	Mid Peak MTWRF 11:01 - 16:00, 20:01 - 23:00 SA, SU, Holidays 07:01 - 23:00	Off Peak Every Day 23:01 - 07:00	MWh
2009-2010	Common Bus	775,265	1,509,816	1,006,724	1,598,716	2,716,073	1,718,249	857,436	1,582,731	1,044,407	2,109,221	3,788,895	2,652,762	21,360,296
2010-2011	Common Bus	753,756	1,421,955	921,010	1,591,621	2,742,144	1,724,046	870,544	1,609,338	1,058,383	2,219,070	4,038,978	2,851,727	21,802,572
2011-2012	Common Bus	779,937	1,523,995	1,004,145	1,638,736	2,781,708	1,745,115	882,807	1,632,557	1,082,679	2,080,554	3,783,755	2,624,185	21,560,172
2012-2013	Common Bus	776,971	1,469,039	965,463	1,631,617	2,862,787	1,778,864	1,010,728	1,688,841	1,163,827	2,214,831	4,209,638	2,933,743	22,706,348
2013-2014	Common Bus	874,653	1,525,616	1,068,430	1,613,602	2,819,211	1,746,787	957,677	1,718,976	1,159,477	2,412,970	4,468,691	3,175,080	23,541,168

<u>Load Forecast and Power Smart Plans MFR 3</u>

Re-File NFAT-MH Exhibits #176-1 and #176-2 Domestic & Export Transmission Losses

As part of this Appendix, Manitoba Hydro is re-filing MH Exhibit #176-1 and MH Exhibit #176-2 provided during the Needs For and Alternatives To proceeding.

NEEDS FOR AND ALTERNATIVES TO (NFAT)

Manitoba Hydro's Response to PUB Question #1

Ref.: PUB/MH II-402, 2005/06 Winter & Summer

1. Please confirm that this is MH's most recent filing of the top 50 winter and top 50 summer peak hours of generation.

2. Provide the average domestic (common bus) and export transmission losses for the 50 top winter and for the 50 top summer loads.

Ref.: PUB/MH II-402, 2005/06 Winter & Summer
Attached Tables (PUB/MH II-402, pp. 2 & 3 of 3 (amended to include incremental loss calculations))

3. Verify or re-calculate the incremental shares (load-squared basis) of the transmission losses going to domestic/common bus firstly and then the exports secondly.

Transmission Losses Incremental Winter Averages		
Domestic	Export	Overall
5.2%	12.55%	8.09%
Incrementally Summer Averages		
5.8%	15.7%	9.59%

4. Provide a monthly tabulation of MH's peak (5x16) and off-peak during both winter and summer energy loads, and HVDC & AC transmission losses for 2005/06 and 2012/13.

Response:

1. Manitoba Hydro filed the top 50 winter and top 50 summer peak hours of generation for the years 2005/06, 2008/09 and 2010/11 in PUB/MH I-041a. The 2005/06 table was refiled in PUB/MH II-402 to include the total system loss calculation for each hour. Therefore, it is confirmed that PUB/MH II-402 is the most recent filing of the top 50 hours of generation for 2005/06.

2. Due to limited time available, statistics for the top 50 summer and winter average domestic (common bus) loads could not be compiled. Manitoba Hydro does not

consider the requested information germane to the analysis of the Preferred Development Plan.

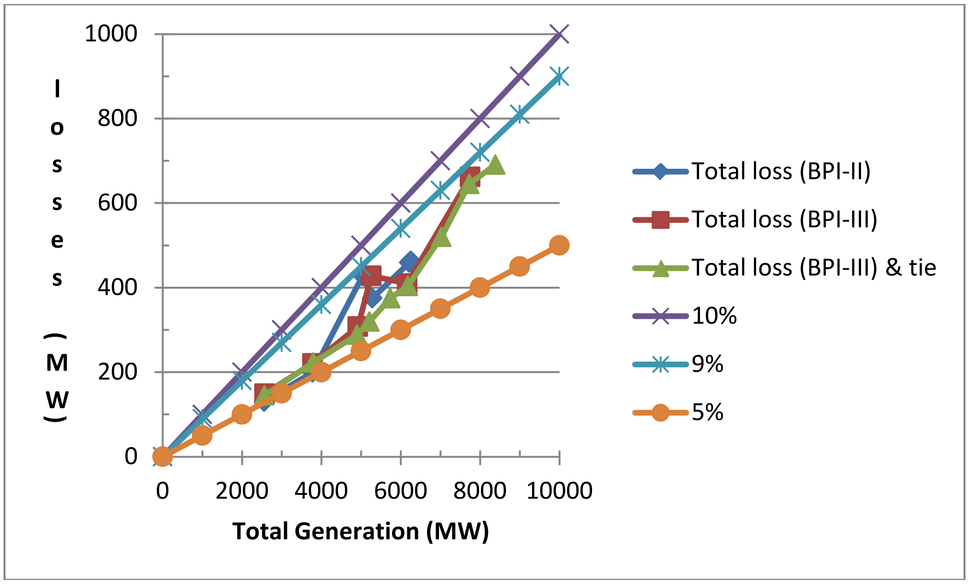
3. The accurate calculation and tracking of system losses and allocation to various load classes including exports is a complex engineering calculation. For this reason Manitoba Hydro has adopted a method for accounting purposes which determines total losses required to supply total load and assigns the same hourly loss/gain ratio to all load classes (residential, commercial, industrial, exports and imports).

   With the exception of load flow studies based on actual hourly system data, Manitoba Hydro does not endorse other incremental loss accounting methodologies including the one requested in this Undertaking. These other methodologies have no technical justification for being more accurate or appropriate than the Manitoba Hydro average loss accounting method as they ignore:

   a) That exports and imports can be scheduled simultaneously at any time during the day,
   b) That all Manitoba Hydro generators can be the source of exports or can be reduced by imports,
   c) That the marginal MW of load being served by Manitoba generation is not always an export MW,
   d) That Manitoba Hydro is not the only entity using its transmission system to export or import from Manitoba as access to Manitoba Hydro's transmission system is available to all as provided under the MH Transmission Tariff,
   e) That loop flows from the US increase losses in Manitoba and are beyond Manitoba Hydro's control. Loop flows are routine and aren't the result of Manitoba Hydro exports activities. However Manitoba Hydro, as a Balancing Authority, must supply this loop flow. In the winter case studied below, average loop flow was 136 MW or about 9% of total exports and for the summer case it was 126 MW or about 6% of total exports.
   f) That a portion of the Manitoba load is served on an interruptible basis equivalent to exports.

   An example of the potential range of losses calculated using an accurate power system model is given in the figure below. The model data used were from the same twenty-one power flow cases provided to Power Engineers[1] with HVdc station losses[2] also included.

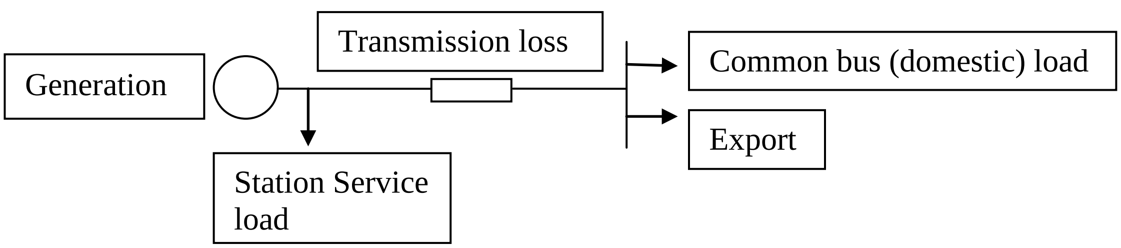
[1] Page 16-19, Power Engineers report to the Public Utilities Board, Jan. 13, 2014.
[2] See PUB/MH II-327b and PUB/MH II-328a



The expected losses ranged between five and nine percent of total generation. In the NFAT analysis Manitoba Hydro has made a conservative assumption of 10%. This value is reasonable for both the existing system and the future system including Bipole III and the new 500 kV tie to the U.S.

However as requested in the Undertaking Manitoba Hydro has calculated incremental losses below using the alternative methodology requested although as explained above it is no more accurate than the Manitoba Hydro practice.

A simple representation of losses in Manitoba can be shown by the following diagram.



Assuming transmission loss is represented by an equivalent resistance (R), then $I_{cb}^2R=Loss_{cb}$. Transmission losses associated with supplying the common bus load is ($Loss_{cb}$). Similar formulas can be derived for transmission losses associated with exports ($Loss_{export}$) and total losses ($Loss_{total}$).

$$I_{cb}^2R=Loss_{cb}$$
$$(I_{cb} + I_{export})^2R=Loss_{total}$$

Substitute $I_{cb} = Load_{cb}/V$ and $I_{export} = Load_{export}/V$ into the above.

$$Loss_{cb}=Loss_{total} * (Load_{cb}^2/(Load_{cb}+Load_{export})^2$$

The above formula assumes common bus (domestic) load is supplied first and exports are supplied next. As mentioned above, this is a hypothetical situation as exports and imports can be scheduled at any time during the day. The results of applying this loss formula are shown in the table below.

Case	A: Load at common bus (MW)	B: MB Exports (MW)	C: Total loss (MW)	D: $A^2/(A+B)^2$ *C Incremental Load losses (MW)	Domestic losses (percent of load at common bus)	E: C-D Incremental Export losses (MW)	Export losses (percent of MB exports)	Total losses (percent of generation)
05/06 Winter	3073	1557	397.6	175	5.70%	222	14.3%	8.1%
05/06 Summer	2365	2091	467.2	132	5.56%	335	16.0%	9.6%

4. Due to limited time available, monthly tabulation of the requested loads and losses could not be compiled. Please refer to PUB/MH II-464b for typical summer and winter peak losses that were analyzed for each of the last 3 years. Total losses, including a breakdown between HVDC and AC losses are given. PUB/MH II-330c can be referred to for an analysis of the losses that occur during various periods including:

- 5×16 summer (peak)
- 5×8 summer (night-time)
- 2×16 summer (weekends)
- 5×16 winter (peak)
- 5×8 winter (night-time)
- 2×16 winter(weekends)

NEEDS FOR AND ALTERNATIVES TO (NFAT)

<u>Manitoba Hydro's Response to PUB Question #2</u>

Ref. PUB/MH I-042a Revised

Confirm the following table is a reasonable extraction from PUB/MH I-042a revised of the incremental HVDC losses for dependable hydraulic energy and for average hydraulic energy minus dependable energy.

Provide another column on each of the four tables in PUB/MH I-042a revised showing the HVDC losses at maximum hydraulic generation.

HVDC
Incremental Transmission Losses (GWh)
Ref.: PUB/MH I-042a

		Dependable	Average minus Dependable	Incremental Losses Maximum minus Average
2013	Bipole I&II	7% (960/13780)	11% (740/6700)	
2019	Bipoles I/II/III w/o Keeyask	5.44% (750/13780)	8.51% (570/6700)	
2022	Bipoles I/II/III with Keeyask	5.54% (930/16780)	8.89% (720/8100)	
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% (930/16780)	10.91% (1095/10750)	

Confirm that domestic load has priority claim on dependable hydraulic generation and that only excess hydraulic generation above dependable is available for export.

Confirm the incremental losses do not include transmission losses from Dorsey or Riel to border and provide those losses under the three flow situations.

Response:

It is not confirmed that the proposed table is a reasonable extraction from PUB/MH I-042a Revised. Expected Losses and Generation are as follows:

HVDC Incremental Transmission Losses (GWh)				
		Dependable Loss/Generation (GW.h)	Average Loss/Generation (GW.h)	Maximum Loss/Generation (GW.h)
2013	Bipole I&II	6.97% 960/13780	8.30% 1700/20480	8.45% 2254/26690
2019	Bipoles I/II/III w/o Keeyask	5.44% 750/13780	6.44% 1320/20480	6.55% 1747/26690
2022	Bipoles I/II/III with Keeyask	5.54% 930/16780	6.63% 1650/24880	7.06% 2218/31430
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% 1410/21260	7.83% 2505/32010	8.34% 3434/41190

		HVDC Incremental Transmission Losses (GWh)			
		Dependable Loss/Generation (GW.h)	Average minus Dependable (GW.h)	Maximum minus Average (GW.h)	Peak Losses (MW)
2013	Bipole I&II	6.97% 960/13780	11.04% 740/6700	8.92% 554/6210	8.69% 308.9/3554
2019	Bipoles I/II/III w/o Keeyask	5.44% 750/13780	8.51% 570/6700	6.88% 427/6210	6.56% 233.2/3554
2022	Bipoles I/II/III with Keeyask	5.54% 930/16780	8.89% 720/8100	9.64% 561/5820	7.22% 305.2/4230
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% 1410/21260	10.19% 1095/10750	10.12% 929/9180	8.71% 486.2/5580

Dependable Conditions reflect annual generation and associated HVDC losses estimated for the dependable flow condition.

Average Conditions reflect the average annual generation and associated HVDC losses under the range of flow conditions.

Maximum Conditions reflect the annual generation and associated HVDC losses under the maximum historic flow condition.

Peak Losses reflects the capacity and associated losses under maximum HVDC loading conditions.

It is not confirmed that domestic load has priority claim on dependable hydraulic generation. Domestic load has a priority claim on the combined dependable energy from thermal, import, purchases and hydraulic generation. Hydraulic generation credits would be assigned as designated under export contracts.

It is confirmed that the above losses do not reflect any losses from Dorsey or Riel to the border. It is not feasible to determine what component of the HVDC generation would be transmitted to the US border from the above information, as losses on the AC system will depend on the level of generation available from generators connected to the AC system, as well as load distribution across the province. Losses on the export interface (to the border) are currently 47 MW when fully loaded at 2175 MW. For the same load (2175 MW) with a new 750 MW interconnection, losses will reduce to 31 MW. When the new interface is fully loaded (2975 MW), losses will increase, back to 52 MW.

Load Forecast and Power Smart Plans MFR 4

MFR #4:
Re-file Power Resource Plan Supply and Demand tables for average energy resources using progressive Incremental (12R)Transmission losses for:

- ***Domestic Load summer and winter (separately) w/o exports***
- ***Adding Peak (5x16) Exports summer and winter (separately)***
- ***Further adding Off-peak Opportunity Exports summer and winter (separately)***

Manitoba Hydro is unable to provide the requested incremental loss information. Increases (decreases) to load (either domestic, firm exports or opportunity exports) will result in an increase (decrease) in losses at the marginal loss rate. In addition, the supply demand tables provide an average of load and supply over a range of flow conditions. Incremental losses cannot be calculated for these aggregate values.

Export & Domestic Revenues MFR 2

File latest Power Resource Plans based on NFAT Plan 5 (2013/14 and 2014/15) Supply and Demand Tables:

- **system power demand (MW) and dependable energy resources (GWh)/average energy resources at generation**
- **system firm winter peak demand and capacity resources (MW) at generation**
- **new system firm summer peak demand and capacity resources (MW) at generation**

A summary system firm winter peak demand and capacity resources (MW) for the years 2014/15 to 2033/34 is provided in Figure 1.

A summary of system firm energy demand and dependable resources (GWh) for the years 2014/15 to 2033/34 is provided in Figure 2.

A summary of System Firm Energy Demand and Resources (GWh) @ generation including 2014/15 at expected water flow conditions, 2015/16 at median water flow conditions and 2016/17 to 2033/34 at the average of all water flow conditions is provided in Figure 3. Please note that the 2014 Base Load Forecast and 2014 Base DSM Forecast entries were corrected for 2014/15 and 2015/16 versus what was included in Figure 9.3 of Tab 9 filed in January 23, 2015.

Manitoba Hydro does not have summer peak demand and capacity tables as requested for the 20 year forecast. As agreed to between Manitoba Hydro and advisors to the PUB, Manitoba Hydro has provided a summary of peak demand and capacity resources (MW) for the months of July 2015 and July 2016 in Figure 4. Surplus capacity in Figure 4 was evaluated consistent with MISO practices.

Figure 1: System Firm Winter Peak Demand and Capacity Resources (MW) @ generation

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	Manitoba Hydro Power Resources																					
	New Hydro																					
	Keeyask G.S.							90	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	Total New Hydro							90	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	New NUG Purchase				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
1	**Total New Power Resources**				**12**	**12**	**12**	**102**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**
	Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
	Existing Thermal																					
	Brandon Unit 5		105	105	105	105	105															
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Total Existing Thermal		385	451	517	517	517	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412
	Imports		605	605	605	605	605	605	605	605	605	605	605	220	220	220	220	220				20
	Bipole III Line Reduction						90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80
2	**Total Base Supply Power Resources**		**6 123**	**6 228**	**6 286**	**6 312**	**6 407**	**6 303**	**6 278**	**6 269**	**6 264**	**6 264**	**6 264**	**5 879**	**5 879**	**5 879**	**5 879**	**5 879**	**5 659**	**5 659**	**5 659**	**5 679**
3	**Total Power Resources**	**1+2**	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 301**	**6 301**	**6 301**	**6 321**
	Peak Demand																					
	2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400	5 458	5 516	5 574	5 632	5 690	5 748	5 808	5 869	5 931	5 995
	Less: 2014 Base DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498	- 517	- 533	- 550	- 566	- 582	- 585	- 589	- 592	- 594	- 596
4	**Manitoba Net Load**		**4 656**	**4 692**	**4 692**	**4 759**	**4 775**	**4 813**	**4 817**	**4 835**	**4 867**	**4 902**	**4 941**	**4 983**	**5 024**	**5 066**	**5 108**	**5 163**	**5 219**	**5 277**	**5 337**	**5 399**
	Contracted Exports		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275	275	275
	Proposed Exports																					
5	**Total Exports**		**726**	**484**	**724**	**724**	**559**	**559**	**779**	**908**	**880**	**880**	**880**	**385**	**385**	**275**	**275**	**275**	**275**	**275**	**275**	**275**
6	**Total Peak Demand**	**4+5**	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**	**5 821**	**5 368**	**5 409**	**5 341**	**5 383**	**5 438**	**5 494**	**5 552**	**5 612**	**5 674**
7	Reserves		513	563	563	571	573	577	578	580	584	588	593	598	603	608	613	620	626	633	640	648
	System Surplus	**3-6-7**	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**	**492**	**556**	**509**	**572**	**525**	**464**	**181**	**116**	**49**	**(0)**

Figure 2: System Firm Energy Demand and Dependable Resources (GWh) @ generation

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	Manitoba Hydro Power Resources																					
	New Hydro																					
	Keeyask							493	2 974	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
	Total New Hydro							493	2 974	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
	New NUG Purchase				97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
1	**Total New Power Resources**				**97**	**97**	**97**	**590**	**3 071**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**
	Existing Hydro		21 928	21 924	21 892	21 878	21 880	21 863	21 816	21 775	21 743	21 743	21 733	21 723	21 723	21 713	21 703	21 703	21 693	21 693	21 683	21 673
	Existing Thermal																					
	Brandon Unit 5		811	811	811	811	811	592														
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Total Existing Thermal		4 118	4 118	4 118	4 118	4 118	3 899	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307	3 307
	Imports		3 440	3 852	3 912	3 912	3 912	3 912	5 304	5 582	5 582	5 582	5 582	5144	5028	4640	4583	4616	4250	4214	4249	4285
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Bipole III Reduced Losses						101	101	177	177	177	177	177	177	177	177	177	177	177	177	177	177
2	**Total Base Supply Power Resources**		**30 257**	**30 665**	**30 693**	**30 679**	**30 782**	**30 546**	**31 375**	**31 612**	**31 580**	**31 580**	**31 570**	**31 122**	**31 006**	**30 608**	**30 541**	**30 574**	**30 198**	**30 162**	**30 187**	**30 213**
3	**Total Power Resources**	**1+2**	**30 257**	**30 665**	**30 790**	**30 776**	**30 878**	**31 136**	**34 446**	**34 711**	**34 680**	**34 680**	**34 670**	**34 222**	**34 106**	**33 708**	**33 641**	**33 674**	**33 298**	**33 262**	**33 287**	**33 313**
	Demand																					
	2014 Base Load Forecast		25 639	26 130	26 436	27 174	27 662	28 247	28 583	28 937	29 284	29 626	29 970	30 316	30 659	31 006	31 352	31 703	32 061	32 424	32 796	33 177
	Construction Power - Hydro			110	110	110	110	110	83													
	Less: 2014 Base DSM Forecast		- 283	- 487	- 780	-1 056	-1 407	-1 730	-1 988	-2 183	-2 296	-2 405	-2 487	-2 562	-2 637	-2 717	-2 797	-2 825	-2 851	-2 874	-2 895	-2 912
4	**Net Load**		**25 356**	**25 753**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 754**	**26 988**	**27 221**	**27 484**	**27 754**	**28 022**	**28 289**	**28 555**	**28 879**	**29 210**	**29 550**	**29 902**	**30 264**
	Contracted Exports		3 421	2 632	3 246	3 366	3 165	3 125	3 951	4 603	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 551	1 389	1 389	1 389	1 389
	Proposed Exports																					
	Less: Total Adverse Water			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 513	- 513	- 513	- 85								
5	**Total Net Exports**		**3 421**	**2 323**	**2 876**	**2 995**	**2 795**	**2 754**	**3 580**	**4 114**	**3 990**	**3 963**	**3 963**	**2 108**	**2 049**	**1 634**	**1 551**	**1 551**	**1 389**	**1 389**	**1 389**	**1 389**
6	**Total Demand**	**4+5**	**28 776**	**28 076**	**28 642**	**29 224**	**29 160**	**29 381**	**30 258**	**30 868**	**30 978**	**31 184**	**31 447**	**29 862**	**30 071**	**29 923**	**30 106**	**30 430**	**30 599**	**30 939**	**31 291**	**31 654**
	System Surplus	**3-6**	**1 481**	**2 589**	**2 148**	**1 552**	**1 718**	**1 754**	**4 187**	**3 843**	**3 702**	**3 496**	**3 223**	**4 360**	**4 034**	**3 784**	**3 535**	**3 244**	**2 699**	**2 323**	**1 996**	**1 659**

Figure 3: System Firm Energy Demand and Resources (GWh) @ generation

2014/15 Expected Water Flow Conditions

2015/16 Median Water Flow Conditions

2016/17 – 2033/34 Average of All Flow Conditions

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	Manitoba Hydro Power Resources																					
	Hydro Generation		35 116	34 418	31 084	31 129	30 907	31 456	34 535	35 275	35 251	35 253	35 138	35 078	35 243	35 141	35 144	35 146	35 224	35 125	35 133	35 157
	Bipole III Reduced Losses						324	324	352	352	352	352	352	352	352	352	352	352	352	352	352	352
	Thermal Generation		101	121	358	383	385	328	166	156	162	154	162	162	170	134	129	131	118	117	116	119
	Existing Wind		918	898	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907
	New NUG Purchase				97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
	Imports		180	328	1 355	1 441	1 445	1 392	1 861	2 042	2 109	2 119	2 218	2 103	2 123	2 079	2 136	2 202	2 103	2 175	2 094	2 149
1	**Total Power Resources**		**36 315**	**35 765**	**33 800**	**33 956**	**34 064**	**34 503**	**37 917**	**38 828**	**38 877**	**38 881**	**38 873**	**38 699**	**38 891**	**38 709**	**38 765**	**38 835**	**38 800**	**38 772**	**38 698**	**38 780**
	Demand																					
	2014 Base Load Forecast		25 589	26 130	26 436	27 174	27 662	28 247	28 583	28 937	29 284	29 626	29 970	30 316	30 659	31 006	31 352	31 703	32 061	32 424	32 796	35 157
	Construction Power - Hydro				110	110	110	110	83													
	Less: 2014 Base DSM Forecast		- 283	- 487	- 780	-1 056	-1 407	-1 730	-1 988	-2 183	-2 296	-2 405	-2 487	-2 562	-2 637	-2 717	-2 797	-2 825	-2 851	-2 874	-2 895	-2 912
2	**Net Load**		**25 306**	**25 643**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 754**	**26 988**	**27 221**	**27 484**	**27 754**	**28 022**	**28 289**	**28 555**	**28 879**	**29 210**	**29 550**	**29 902**	**32 245**
3	Contracted Exports		4 537	4 051	3 373	3 438	3 232	3 192	4 474	5 343	5 278	5 251	5 251	2 969	2 825	2 286	2 167	2 167	2 005	2 005	2 005	2 005
4	**Total Demand**	**2+3**	**29 843**	**29 694**	**29 139**	**29 667**	**29 598**	**29 819**	**31 153**	**32 097**	**32 266**	**32 472**	**32 735**	**30 723**	**30 847**	**30 575**	**30 722**	**31 046**	**31 215**	**31 555**	**31 907**	**34 250**
	System Surplus	**1-4**	**6 472**	**6 071**	**4 661**	**4 290**	**4 466**	**4 684**	**6 764**	**6 731**	**6 611**	**6 409**	**6 138**	**7 976**	**8 044**	**8 134**	**8 043**	**7 789**	**7 585**	**7 217**	**6 791**	**4 530**

Figure 4: Summer Peak Demand and Capacity Resources (MW) @ generation (based on MISO surplus capacity calculations)

Notes / Row	Month	Jul-2015	Jul-2016
	Supply		
1	Total Generation Capacity	5474	5474
	Capacity Imports	0	0
2	Total Supply	5474	5474
	Peak Demand		
	2014 Base Load Forecast	3341	3384
	Less: 2014 Base DSM Forecast	71	116
	Less: Curtailable Load, Station Service	166	166
	Plus: 10% Export Losses	110	132
3	Manitoba Net Load	3214	3234
4	Capacity Exports	1073	1292
5	Total Peak Demand (3 + 4)	4287	4526
6	MISO Planning Reserves	228	230
7	**Surplus (2 - 5 - 6)**	**959**	**718**

Notes:

1. MISO capacity surplus based on generation unforced capacity (i.e. net of forced outage rate). Figure includes all MH supplies however, not all MH generation is necessarily offered to capacity market (e.g., Brandon 5 generation excluded)

6. MISO planning reserve (7.1%)

Manitoba Hydro

Response to Public Utilities Board Order 43/13, Directives 8 & 9

February 27, 2015

INDEX

1.0 OVERVIEW

The purpose of Appendix 11.48 is to provide additional information to the Public Utilities Board (PUB) to assess the financial impact of a change to the Equal Life Group (ELG) method of depreciation from Manitoba Hydro's existing Average Service Life (ASL) method. This is in response to PUB Order 43/13 following Manitoba Hydro's 2012/13 and 2013/14 General Rate Application (GRA) hearing. The key observations with respect to this Appendix are as follows:

1. International Financial Reporting Standards (IFRS) are more explicit than Canadian Generally Accepted Accounting Principles (CGAAP) for calculating depreciation, requiring a more granular level of asset componentization and recognizing gains and losses on asset retirements into income immediately.

2. The ELG and ASL methods are fundamentally different in terms of how they calculate depreciation expense for an asset component group. The ASL method calculates the annual depreciation expense based on the overall average service life of all the assets in a component group whereas the ELG method sub-divides the assets in a component group into sub-components of assets with very similar service lives and calculates depreciation separately for each sub-component to arrive at the total depreciation for the larger component group.

3. Manitoba Hydro's existing asset component groups include assets with a wide range of service lives which, if applying the ASL method, will not produce an annual depreciation expense that complies with IFRS. To continue to use the ASL method under IFRS, Manitoba Hydro will have to increase the number of its asset components.

4. Manitoba Hydro estimates it would take at least two years to identify and implement the new asset components required to continue with the ASL method under IFRS at a cost in excess of $2 million. These costs can be avoided and compliance with IFRS achieved by adopting the ELG method which calculates depreciation at a more granular level within existing asset component groups; satisfying the componentization requirements of IFRS.

5. The change to the ELG method will result in a similar increase ($36 million) in estimated annual depreciation expense, compared to an IFRS compliant ASL

method ($33 million) for the March 31, 2014 account balances. When the impacts of gains and losses on asset retirements are considered, the total expense could be higher under an ASL method.

6. The analysis performed on the Bipole III and Keeyask capital additions indicates the ELG method annual depreciation expense is $0.7 million lower than the depreciation expense calculated under the ASL method for these projects.

7. The depreciation changes that are proposed by Manitoba Hydro, when considered on the whole, are not driving the need for increases in customer rates. The overall decrease in the test years ranges between $25 to $57 million annually. By the end of the 10-year forecast period, depreciation expense is expected to decrease by more than $100 million annually.

8. Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole rather than focusing only on the change to ELG.

2.0 BACKGROUND

In its 2012/13 and 2013/14 GRA, Manitoba Hydro informed the PUB that it would be changing from the ASL method of group depreciation to the ELG method upon its transition to IFRS for financial reporting purposes in order to facilitate compliance with the requirements of IFRS.

The PUB was concerned that not enough information was provided during the hearings to assess the impact on rate payers of the change to the ELG method. One of the key concerns identified during the hearing was the increase in depreciation expense in the years following the transition to IFRS. At the conclusion of Manitoba Hydro's 2012/13 and 2013/14 General Rate Application hearing process, the PUB found the following (page 18 of PUB Order 43/13):

- *The Board also is concerned that not enough information has been provided to date to assess the true impact on ratepayers of a switch to Equal Life Group. As such, the Board will require Manitoba Hydro to file additional information, including a determination of depreciation rates and schedules based on the Average Service Life methodology, to provide a meaningful comparison between the two approaches. The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to specify what, if any, increased componentization is required, and at what cost.*

Based on their findings, the PUB issued the following directives to Manitoba Hydro in Order 43/13:

> *8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*
>
> *9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

Subsequent to the receipt of Order 43/13, Manitoba Hydro exchanged correspondence with the PUB to clarify its interpretation of the Order and to inform the PUB that Manitoba Hydro would not be in a position to complete a full depreciation study based on an IFRS compliant ASL methodology in time for its next GRA. Following this exchange, Manitoba Hydro documented its intention to provide a comparison of the ELG and IFRS compliant ASL depreciation methodologies on a representative sample basis in order for the PUB to assess the financial impact of the change in depreciation method. This correspondence is provided in Attachment B of this document.

Included in this response is an identification of the differences between the requirements of CGAAP and IFRS as it pertains to the determination of depreciation expense and the reasons for changing to the ELG method. In addition, Manitoba Hydro has outlined the differences between the ASL and ELG methodologies and explained its reasons for changing to the ELG method upon transition to IFRS. Lastly, Manitoba Hydro has provided an analysis on a representative sample basis, in response to directives #8 & #9 from PUB Order 43/13.

Manitoba Hydro engaged the consulting firm of Gannett Fleming Canada ULC (Gannett Fleming) to calculate the annual depreciation expense for the March 31, 2014 asset groups identified using the ASL method applied to the sample additional asset component groups and using the ELG method based on the current level of asset componentization. Gannett Fleming also calculated ASL and ELG depreciation expense calculations for the sample forecast Bipole III and Keeyask asset component balances in a similar manner as the calculations for the March 31, 2014 asset balances. The study and analysis performed by Gannett Fleming is included in Attachment A of this document.

3.0 COMPARISON OF DEPRECIATION: CGAAP VS. IFRS

Two significant differences exist between CGAAP and IFRS as it applies to the depreciation of property, plant and equipment (PP&E).

1. IFRS is more explicit than CGAAP in terms of how depreciation is to be determined. Under IFRS, a separate component is required when a plant item is comprised of significant individual cost components that are consumed over different periods of time, such that different depreciation rates are appropriate for each component. A separate component may be either physical, such as a runner on a turbine, or non physical, such as a major inspection or overhaul. The general rule when complying with IFRS is that a separate component group is required when an item is material in cost and has a service life different than that of other assets, such that the depreciation on that item will have a material impact on net income.

   Although CGAAP encourages that assets be broken down into separate components for determining annual depreciation, it is much less explicit, such that many utilities, including Manitoba Hydro, have not developed depreciation component groups to the extent required for compliance with IFRS if using the ASL method. As IFRS requires a greater the level of componentization, depreciation expense will be higher for a given group of assets over the first half of the asset group’s service life. This occurs because the increase in the annual depreciation expense on assets with a service life less than the average exceeds the decrease in annual expense of assets with a service life longer than the average.

2. IFRS explicitly states that gains and losses on asset retirements are to be recognized immediately to net income. Currently under CGAAP, Manitoba Hydro follows a common industry practice for regulated utilities whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset’s respective component group. Such gains and losses are then factored into future depreciation rate changes for the component group and are recognized in net income over time, as part of future years’ depreciation expense.

In order to comply with the componentization requirements of IFRS and to minimize the magnitude of annual asset retirement gains and losses on net income, Manitoba Hydro is changing to the ELG method of depreciation for financial reporting purposes.

The following sections further explain Manitoba Hydro’s decision to change to the ELG methodology.

4.0 COMPARISON OF ASL AND ELG DEPRECIATION METHODS

4.1 Group Depreciation:

Generally, the greater the number of separate asset component groups used for calculating depreciation expense, the greater the accuracy of the depreciation expense calculation. With greater accuracy, however, comes an increase in administrative efforts to maintain a larger volume of asset components (e.g. more components to allocate time to, additional asset records to update, larger database files to maintain, etc).

Group depreciation procedures are used to depreciate plant assets when the volume of assets to be depreciated is so large that it is not practical or efficient for an entity to perform depreciation calculations on each individual plant item; such is the case for large utilities. Grouping assets with similar service lives for calculating depreciation allows for a consistent and efficient method of calculating depreciation across a large volume of assets. The group depreciation method recognizes that not all the items in a specific group will have identical service lives, but instead will have lives that are dispersed over a range of time. The extent of dispersion in the services lives of the assets will impact the accuracy of the annual depreciation expense for the individual assets within the group for a given point in time. The two more common group depreciation methods are the Average Service Life and Equal Life Group methods.

4.2 **Average Service Life Method**:

Under CGAAP, Manitoba Hydro currently uses the ASL method and follows a common industry practice for regulated utilities of recognizing gains and losses on asset retirements in accumulated depreciation. The ASL method calculates depreciation expense based on the average service lives of the assets in a component group. The key advantage of this approach is that it is simple to apply. The extent in which this approach accurately reflects the consumption of an asset component group on an annual basis, however, depends on the extent to which the depreciation from assets that are under-depreciated (i.e. have a shorter life than the average) is balanced by the depreciation on assets that are over depreciated (i.e. have a longer life than the average).

The annual depreciation expense recorded by Manitoba Hydro under CGAAP does not comply with the componentization requirements of IFRS due to the wide dispersion that currently exists in the service lives of many asset groups. In order to be compliant with

IFRS using the ASL method, Manitoba Hydro would have to increase the number of asset component groups of similar lived assets so that the range of service lives in any one group is smaller than currently exists. A larger number of asset component groups would also minimize the extent of gains and losses that must be recognized immediately to net income under IFRS as assets are being amortized over a more representative service life.

4.3 Equal Life Group Method:

The information required to determine annual depreciation under the ELG method is the same as that required for the ASL approach. This information includes the average service life of the assets in the group, retirement dispersion, net salvage and the age distribution of the assets in the component group. The ELG method of group depreciation, however, takes a different approach than the ASL method to calculating depreciation expense for an asset component group by recognizing the existence of retirement dispersion in the group.

The ELG calculation sub-divides the asset group into sub-components of estimated equal life and depreciates these sub-components over their respective service lives as opposed to the average life of the group as applied by the ASL method. The resulting annual depreciation expense for the asset group is the summation of the calculated depreciation based on the service life of each equal life group. This results in a similar depreciation expense to applying the ASL method to a larger number of component groups consisting of assets with the same service lives. This concept is demonstrated in Attachment A to this document where the application of the ASL method to a more componentized Manitoba Hydro asset structure produces comparable results to the ELG method applied to Manitoba Hydro’s existing asset components. Where asset service life dispersion does not exist in an asset component group, the ELG and ASL methods will calculate the same depreciation expense.

Effectively, the ELG method is more representative of an asset’s annual depreciation than an ASL method when applied to asset groups with a wide dispersion in service lives because the ELG method more accurately allocates the cost of a group of assets to annual expense in accordance with the consumption of the assets. The concept of accurately charging the annual cost of an asset to the ratepayer based on the assets consumption supports the regulatory goal of intergenerational equity in setting customer rates. This is also a fundamental concept of IFRS as published by the International Accounting

Standard Board *"Clarification of Acceptable methods of Depreciation and Amortization, Amendments to IAS 16 Property, Plant & Equipment and IAS 38 Intangible Assets"* which amends the requirements of IAS 16 and IAS 38 to clarify that a depreciation method that is based on revenue is not appropriate because such a method reflects a pattern of generation of economic benefit from an asset rather than the pattern of consumption of an asset's expected future economic benefits.

The following simple example in Figure 1 below demonstrates the difference in the calculation between the ELG and ASL methods of depreciation:

Figure 1

Assumptions:

Component Group A	Cost	Service Life (Years)	Salvage	ASL Depreciation Rate	ELG Depreciation Rate
Asset 1	$ 100	1	0		100%
Asset 2	$ 100	2	0		50%
Asset 3	$ 100	3	0		33%
Average Service Life		2		50%	

ASL Depreciation Calculation	Asset 1	Asset 2	Asset 3	Total Depreciation	Total Loss (Gain) on Retirement	Total Expense
	$ 100	**$ 100**	**$ 100**			
Depreciation Year 1	50	50	50	$ 150		
Retirement	(100)	-	-			
Loss (Gain) on Retirement	50				$ 50	**$ 200**
Depreciation Year 2	-	50	50	$ 100		
Retirement		(100)				
Loss (Gain) on Retirement		-			$ -	**$ 100**
Depreciation Year 3	-	-	50	$ 50		
Retirement			(100)			
Loss (Gain) on Retirement			(50)		$ (50)	**$ -**
Total				$ 300	$ -	**$ 300**

ELG Depreciation Calculation	Sub Component Asset 1	Sub Component Asset 2	Sub Component Asset 3	Total Depreciation	Total Gain (Loss) on Retirement	Total Expense
	$ 100	**$ 100**	**$ 100**			
Depreciation Year 1	100	50	33	$ 183		
Retirement	(100)	-	-			
Loss (Gain) on Retirement	-				$ -	**$ 183**
Depreciation Year 2	-	50	33	$ 83		
Retirement		(100)				
Loss (Gain) on Retirement		-			$ -	**$ 83**
Depreciation Year 3	-	-	33	$ 33		
Retirement			(100)			
Loss (Gain) on Retirement			-		$ -	**$ 33**
Total				$ 300	$ -	**$ 300**

Observations pertaining to the example above are as follows:

- The level of asset componentization impacts annual depreciation expense. Had the assets in **Group A** been divided into three separate component groups based on their service lives, as is required under IFRS, then the annual depreciation expense would have been equal to the expense determined under the ELG method.

- When retirement dispersion exists in a group, there is a deferral and acceleration of depreciation under the ASL procedure as the ASL method depreciates assets with different service lives over the average life for the group. The longer-lived asset must be over depreciated to make up for the under depreciation on the shorter lived asset. The accuracy of the overall depreciation expense depends on the extent to which the over and under depreciation is balanced for the group of assets.

- When applying the ASL method, the combination of a wide range of service life dispersion with the IFRS requirement to immediately recognize asset retirement gains and losses will result in an increase in volatility in net income. In the example, the loss on retirement of asset 1 results in a higher total expense (depreciation plus losses) in the first year under the ASL method compared to the total expense using the ELG method. Under the ELG method, no gains or losses occurred on asset retirements since the assets were being depreciated over their individual service lives. This point demonstrates that although the change to the ELG method results in an increase to depreciation expense in the early years, when asset retirement losses are considered the ASL method can result in an overall higher expense.

- The ELG method better promotes intergenerational equity by matching the cost with the consumption of an asset. As per the example, using the ASL method, intergenerational equity is not met as the rate payer benefited from the use of Asset 3 in year 3, but was not charged for the asset in that year. The $50 depreciation expense is completely offset by the $50 gain that was recognized when the asset was retired at the end of year 3. The $50 gain is the result of the over depreciation on the asset in years 1 and 2.

5.0 ADDITIONAL COMPONENTIZATION REQUIREMENTS FOR MANITOBA HYDRO USING AN IFRS COMPLIANT ASL METHOD

Manitoba Hydro's existing level of componentization does not comply with the requirements of IFRS. Manitoba Hydro can find numerous examples where its current level of depreciable components would need to be broken down into additional components based on asset dollar cost and different service lives in order to continue with the ASL method under IFRS.

Examples where additional component groups could be developed based on estimated asset service lives are provided in Figure 2 below:

Figure 2

Asset Category	Existing Component (Service Life)	Potential New Components (Service Life)
Hydraulic Generation	Water Control Systems (65)	Water Control Systems (65) Trash, Safety & Ice Booms (20)
Hydraulic Generation	Turbines & Generators (60)	Turbine - Primary Structure (75) Turbine - Instrumentation and Electrical (20) Generator – Primary Structure (50) Generator – Instrumentation & Electrical (20)
Hydraulic Generation	A/C Electrical Power Systems (55)	A/C Electrical Power Systems (55) Generator Step up Transformers before 1950 (60) Generator Step up Transformers post1950 (40)
Distribution	Poles and Fixtures (65)	Wood Poles and Fixtures (65) Cross arms (35)
Distribution	Concrete Ductline and Manholes (75)	Concrete Ductline (75) Manholes (60)
Transmission	Poles and Fixtures (55)	Wood Poles (60) Cross Arms & Fixtures (30)
Transmission	Metal Towers & Concrete Poles (85)	Metal Towers and Concrete Poles (85) Concrete Footings (45)
Substations	Other Transformers(50)	Potential & Current Transformers (60) Station Service & Other (40)
Substations	Interrupting Equipment (50)	Vacuum Circuit Breakers (20) Min oil and SF6 Breakers (40) Air Magnetic Breakers (50) Air Blast & Oil Bulk Breakers (100) Other Interrupting Equipment (50)

Asset Category	Existing Component (Service Life)	Potential New Components (Service Life)
HVDC	Synchronous Condensers & Unit Transformers (65)	Synchronous Condensers (65 yrs) Unit Transformers (40 yrs)
Communication	Carrier Equipment (20)	Power Line Carrier, Microwave & Optical Transport (20) VHF Network (15) Standby Power Systems – Diesel (30) Standby Power Systems – Batteries & Auxiliaries (18) Span Line & High Voltage interface (35)
Buildings	360 Portage Electro/Mechanical	Finishes (20) Windows and Other (40) Millwork and Elevators (60) Interior Glaze/Drywall and Electrical (75)

The process for identifying and developing new asset component groups based on materiality of cost and differences in service life is complicated with regards to determining the actual historical costs and age for the assets that are included in the component groups. Cost and age information is required for each asset within a component group in order to determine the depreciation period, rates and the calculation of future gains and losses when the assets are retired.

Manitoba Hydro's historical asset cost and age information is comprised of thousands of transactions per year that were not captured at the level of detail required to readily develop new asset component groups. Such records date back over 70 years and are not available electronically for anything that was placed in service prior to the adoption of SAP in 1998. As a result, conversion into IFRS compliant components would require an extensive manual effort by both finance and engineering staff. For example, the records for a particular project may have captured only the total cost of a generator from the supplier as opposed to separately identifying the costs of the generator and its instrumentation and electrical components. Manitoba Hydro estimates that it would take at least two years to identify and implement the appropriate historical opening cost balances for newly identified asset components in order to continue to use the ASL method and comply with the requirements of IFRS.

This issue is not unique to Manitoba Hydro as identified by the accounting firm Price Waterhouse Coopers in their May 2014 document titled, ***"Financial reporting in the power and utilities industry, International Financial Reporting Standards, Identifying components of an asset:*** *Generating assets might comprise a significant number of components, many of which will* *have differing useful lives. The significant components of these types of assets must be separately identified. This can be a complex process, particularly on transition to IFRS, because the detailed record keeping needed for componentisation might not have been required in order to comply with national generally accepted accounting principles (GAAP). This can particularly be an issue for older power plants."*

Manitoba Hydro estimates that the cost to the rate payer to identify, develop, and convert existing asset component groups into additional groups for compliance with IFRS (assuming the ASL method) would cost in excess of $2 million, depending on the level of detail in the accounting records. The majority of these costs would include analyzing historical project and operational records, performing a detailed depreciation study (including consulting services), converting existing accounting records and related IT systems, and change management activities associated with training staff on the new components.

6.0 ANALYSIS: COMPARISON OF ELG AND AN IFRS COMPLIANT ASL METHOD

In response to PUB Order 43/13, directives #8 & #9, which requested additional information to compare a change to the ELG method to a change to an IFRS-compliant ASL method, Manitoba Hydro developed two representative samples of additional asset component groups for significant asset categories. One representative sample is based on the March 31, 2014 asset component balances and a second representative sample is based on significant forecast asset additions (Bipole III and Keeyask) over the ten year forecast period. The additional components were developed through discussions with Manitoba Hydro engineering staff, Gannett Fleming and through a review of available historical asset records and project estimates.

The additional sample asset components developed for the analysis are listed in Figure 1, page II-5 of the Gannett Fleming report in Attachment A.

The results of the comparison performed by Gannett Fleming in Attachment A indicate that an IFRS-compliant ASL approach will produce a comparable depreciation expense to the ELG method applied to a fewer number of asset components. The results are summarized in Figure 2, page III-3 of Attachment A.

March 31, 2014 Account Balances:

The analysis performed on the March 31, 2014 account balances results in a $0.7 million difference, for the sample, between an IFRS-compliant ASL and ELG method. Extrapolating the $0.7 million difference to 100% of the asset balances indicates that that an IFRS compliant ASL approach would result in a lower annual depreciation expense of approximately $3.5 million. The implementation of an IFRS compliant ASL method would result in an increase in overall annual depreciation expense of approximately $33 million, compared to a $36 million increase under the ELG method, without consideration for the impacts of gains and losses on asset retirements. The analysis performed demonstrates that compliance with the depreciation requirements of IFRS will result in a similar increase in depreciation expense, regardless of the depreciation method used.

Capital Expenditure Forecast (CEF-14):

The analysis performed on a sample of forecast additions for the Bipole III and Keeyask projects results in a $0.1 million difference, between an IFRS-compliant ASL and ELG method. Extrapolating the $0.1 million difference to 100% of forecast additions for those projects indicates that that an IFRS compliant ASL approach would result in a higher annual depreciation expense of approximately $0.7 million.

The analysis demonstrates that an increase in annual depreciation expense will occur as a result of the need for Manitoba Hydro to comply with the more explicit componentization requirements of IFRS; regardless of whether the ELG or ASL method is applied. Overall, the differences calculated between the ASL and ELG approaches, is not significant enough to impact customer electricity rates.

Moreover, Manitoba Hydro wishes to emphasize to the PUB that on an overall basis, the proposed changes to depreciation are significantly reducing the Corporation's depreciation expense. The overall decrease in the test years ranges between $25 to $57 million annually. By the end of the 10-year forecast period, depreciation expense is expected to decrease by more than $100 million annually. Please refer to the following table, which is an excerpt from Schedule A of Appendix 5.7 of the Application.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Electric only (in millions of $'s)										
DEPRECIATION EXPENSE										
Average Service Life Changes (2014 Depreciation Study)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)
Administrative Overhead		(0)	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)
Meter Compliance, Exchange and Sampling		0	0	0	0	0	0	1	1	1
Removal of Net Salvage		(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)
Change to IFRS Compliant Depreciation		36	38	41	49	55	63	67	68	69
Subtotal Depreciation Changes	**(25)**	**(53)**	**(57)**	**(60)**	**(76)**	**(86)**	**(96)**	**(101)**	**(103)**	**(105)**

Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole rather than focusing only on the change to ELG.

The depreciation changes that are proposed by Manitoba Hydro, when considered on the whole, are not driving the need for increases in customer rates. As such, Manitoba Hydro sees no incremental benefit to the rate payer of incurring additional costs to further componentize its assets to continue with the ASL depreciation method under IFRS. Additional componentization would be very costly and would require additional administrative efforts to maintain.

Manitoba Hydro

GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTILITIES BOARD DECISION 43/13

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

MANITOBA HYDRO

Winnipeg, Manitoba

GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTILITIES BOARD DECISION 43/13

GANNETT FLEMING CANADA ULC

Calgary, Alberta

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MANITOBA HYDRO

GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTITLTIES BOARD DECISION 43/13

EXECUTIVE SUMMARY

Gannett Fleming Canada ULC ("Gannett Fleming") was retained by Manitoba Hydro for assistance in responding to directives #8 and #9 from Public Utilities Board Order 43/13 for Manitoba Hydro's 2014/15 and 2015/16 General Rate Application (GRA). The directives requested information with respect to an analysis of the level of asset componentization that would be required to develop IFRS – compliant depreciation rates using the ASL procedure and an analysis comparing the depreciation expense resulting from the conversion to the ELG procedure as compared to the depreciation expense resulting from the use of an IFRS compliant ASL procedure.

In order to strictly comply with Directive #8, a detailed analysis of virtually all of the current Manitoba Hydro accounts would be required which, given the extreme volume of account information, could not be completed in time for the current GRA. In order to reasonably respond to the directives in the time period allotted, Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further analysis. Representative sample components and comparisons between ELG and IFRS compliant ASL depreciation calculations were developed for both the March 31, 2014 account balances and the forecasted Bipole III and Keeyask projects. The sample accounts chosen represent approximately 20% of the total March 31, 2014 asset balance and 20% of the 10 year forecast project balances and are thus, sufficiently representative of the investment base being analyzed.

The analysis completed by Gannett Fleming on the March 31, 2014 balances, resulted in a $738,000 difference between the depreciation calculated using the ELG method and the depreciation calculated using the ASL method. Extrapolated across the full March 31, 2014 asset balance, the ELG method is $3.5 million higher on an annual basis than the ASL method applied to more components. The analysis completed on the forecasted Bipole III and Keeyask projects resulted in a $140,000 difference between the ELG and IFRS-compliant ASL methods where the ELG procedure was lower than the IFRS compliant ASL procedure. Extrapolated across the forecasted asset balances, the ELG method is $0.7 million lower of the analyzed projects than the ASL method.

Based on the results of the testing presented in this report, Gannett Fleming views that the statements made by Manitoba Hydro in its previous GRA proceeding regarding the fact that an IFRS compliant ASL procedure would result in a similar level of depreciation expense as the proposed change to the ELG procedure have been demonstrated.

PART I. INTRODUCTION

MANITOBA HYDRO
GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTITLTIES BOARD DECISION 43/13

PART 1. BACKGROUND AND SCOPE

BACKGROUND

In its 2012/13 and 2013/14 General Rate Application ("GRA"), Manitoba Hydro informed the PUB that it would be changing from the Average Service Life ("ASL") procedure to the Equal Life Group ("ELG") procedure in the calculation of the depreciation rates upon its transition to IFRS in order to facilitate compliance with the requirements of IFRS. Mr. Larry Kennedy of Gannett Fleming Canada ULC ("Gannett Fleming") provided expert testimony relating to the enhanced ability of the ELG procedure to comply with the requirements of the IFRS without the need for additional componentization, as would be required to continue with the ASL procedure under IFRS. One of the key concerns identified during the hearing was the increase in depreciation expense resulting from the change to the ELG method in the years following the transition to IFRS. It was the stated view of Mr. Kennedy that the additional componentization that would be required in order to apply the ASL method under IFRS would result in a similar increase in depreciation expense. The advantage to changing to the ELG method is that very little additional componentization is required which significantly reduces existing and ongoing efforts and costs by Manitoba Hydro to comply with IFRS.

Based on their findings in Manitoba Hydro's GRA, the PUB issued the following directives to Manitoba Hydro as a means to better understand the differences between the ASL and ELG methodologies:

> ***8.*** *That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*

***9.** That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

SCOPE OF STUDY

Gannett Fleming was retained by Manitoba Hydro to provide an analysis of the level of asset componentization that would be required to develop IFRS – compliant depreciation rates using the ASL Procedure and to model a comparison of the depreciation expense resulting from the conversion to the ELG procedure as compared to the depreciation expense resulting from the use of an IFRS compliant ASL procedure. This report presents a discussion of the analysis undertaken by Gannett Fleming and provides the comparative results from the analysis.

Strict compliance with Directive 8 from the Public Utilities Board Order 43/13 would require a detailed analysis of virtually all of the current Manitoba Hydro accounts. Such an analysis would require the detailed manual review of over 70 years of detailed project capitalization records, many years of detailed retirement transactions, and a detailed review of the current investment in all accounts. These reviews are required in order to determine the amount of investment by installation year for accounts that could be componentized further, and to appropriately develop a retirement rate analysis for the support of an average life estimate for each of the new components. Additionally, the accumulated depreciation accounts would require the same level of componentization as the related asset accounts.

In order to reasonably respond to PUB Order 43/13, directives #8 and #9 in time for Manitoba Hydro's 2014/15 and 2015/16 GRA, Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further review and analysis.

This report outlines the manner in which a representative sample of accounts were selected for analysis and review; presents an overview of the manner in which each of the components where assigned an average service life estimate for use in this analysis; describes the manner in which the review was undertaken; and will provide a summary of the analysis and the conclusions of Gannett Fleming resulting from the study.

PART II. ANALYSIS AND REVIEW

PART 2. ANALYSIS AND REVIEW

SELECTION OF THE MARCH 31, 2014 COMPONENTS TO REVIEW

Gannett Fleming is a large internationally acclaimed professional engineering firm that has been active in the design, construction and inspection of Dams, Levees and Hydroelectric infrastructure since 1915. Gannett Fleming is a member of the Canadian Dam Association ("CDA") and frequently presents on a number of issues to the membership of the CDA. In addition to reliance on the Manitoba Hydro engineering and operations staff, senior leadership staff of the Gannett Fleming Dam and Earth Sciences group were consulted during various phases of this project to ensure that the Gannett Fleming recommendations regarding componentization reasonably reflect current and historic engineering practices related to dams and levees.

Based on the broad experience of Gannett Fleming developing depreciation practices and policies ensuring compliance with the IFRS for utilities across Canada, Gannett Fleming does not view that the current level of Manitoba Hydro asset componentization is sufficient if using the ASL method for financial statements prepared under IFRS. In the experience of Gannett Fleming, electric generation utilities across Canada that use the ASL procedure have a significantly increased level of componentization for financial reporting purposes[1].

Gannett Fleming views that Manitoba Hydro's current level of depreciable components would need to be broken down into additional components based on asset dollar value, differing service lives and differing forces of retirement in order for Manitoba Hydro to continue using the ASL procedure in the development of depreciation rates under the IFRS.

Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further review and analysis based on the following:

- Where it is easily apparent that the current group will not meet the componentization requirements of the IFRS;

[1] Including BC Hydro, Newfoundland and Labrador Hydro and SaskEnergy.

- Where a reasonable estimate of the average service life can be determined by operational staff. In this manner, a reasonable estimate of the service life estimate for the new accounts could be made without the detailed review of all historic retirement information;
- Where the current groups selected will provide a statistically significant sample size such that the results can be considered to be representative of a full review of accounts.
- Where the resultant groups selected represent a reasonable cross sample of accounts and facilities.

Based on the above criteria, the following accounts were selected for analysis:

- Turbines and Generators – Generation
- A/C Electrical Power Systems – Generation
- Poles and Fixtures – Transmission
- Other Transformers – Transmission
- Interrupting Equipment – Substations
- Poles and Fixtures – Distribution
- Buildings – 360 Portage – Electro/mechanical

The data used in the 2014 depreciation study as filed in this application was used for the analysis and componentization. As of March 31, 2014 the above account groups represented $2.9 billion of Manitoba Hydro's total March 31, 2014 cost base of $14.2 billion (or 20%). In the view of Gannett Fleming, a sample size representing 20% of the total investment comprising a broad cross section of asset groups is representative of the investment as a whole.

In order to compare the impacts of the ELG procedure to an IFRS compliant ASL procedure on a large level of new investment as identified in Manitoba Hydro's Capital Expenditure Forecast (CEF-14), current component groups relating to the future investment for the Bipole III and Keeyask Generating Station projects were tested. These two projects represent 55% of the total electric operations capital forecast over the next 10 years and the sample accounts selected represent approximately 20% of the project's balance. Specifically, the following component groups related to the new investment of the above two projects were identified for specific review:

- Synchronous Condensers and Unit Transformers – Bipole III
- Converter Equipment – Bipole III
- Water control Systems – Keeyask
- Turbines and Generators – Keeyask
- A/C electrical Power Systems – Keeyask

Figure 1, on the following page identifies the current components and the further componentized new groupings used for the purposes of comparative testing. Gannett Fleming notes that this level of componentization and new component development is reasonable for the purposes of testing in order to comply with the PUB directives. However, the continued use of an IFRS compliant ASL procedure would require a significant amount of additional review of the tested components, in addition to a complete review of all components not included in the sample.

Figure 1 – Summary of the Representative Sample of Existing and Additional Components Used in the Gannett Fleming Testing

March 31, 2014 Accounts:

Existing Asset Component	Existing Asset Component
- Turbines and Generators (Generation)	- Turbines - Generators
- A/C Electrical Power Systems (Generation)	- Step-up transformers manufactured before 1950 - Step-up transformers manufactured in 1950 or later - A/C Electrical Power Systems – other equipment
- Poles and Fixtures (Transmission)	- Wood Poles and Fixtures - Cross-arms
- Other Transformers (Substations)	- Other Transformers - Potential and Current Transformers
- Interrupting Equipment (Substations)	- Other Interrupting Equipment - Vacuum Circuit Breakers - Min Oil and SF6 Breakers - Air Magnetic Breakers - Air Blast and Oil Bulk Breakers
Existing Asset Component	**Existing Asset Component**
- Poles and Fixtures (Distribution)	- Wood Poles and Fixtures - Cross-arms
- Buildings (360 Portage) – Electro/mechanical	- Finishes - Mechanical/Windows and Other - Millwork and Elevators - Interior Glaze/Drywall and Electrical

Capital Expenditure Forecast (CEF-14):

Existing Asset Component	Test Sample Asset Component
- Synchronous Condensers and Unit Transformers (Bipole III)	- Synchronous Condensers - Unit Transformers
- Converter Equipment (Bipole III)	- HVDC Converter Valves and Valve Cooling Equipment - HVDC Converter Transformers
- Water Control Systems (Keeyask)	- Water Control Systems - Ice, Debris and Public Safety Booms
- Turbines and Generators (Keeyask)	- Turbines - Generators
- A/C Electrical Power Systems (Keeyask)	- Step-up transformers manufactured in 1950 or later - A/C Electrical Power Systems – other equipment

DEVELOPMENT OF AVERAGE SERVICE LIFE ESTIMATES FOR THE NEW COMPONENT GROUPS

In order to test the impacts of the ELG Procedure to an IFRS compliant ASL procedure, an average service life estimate is required for the additional level of componentization used in the development of the ASL depreciation expense. The average service life estimates as used in the depreciation study filed with Manitoba Hydro's current application were used as the basis for the development of the new more componentized average service life estimates. The comparisons to the ELG procedure used average service lives as used in the current 2014 depreciation study.

Gannett Fleming notes that in the development of the additional components, the componentization used for ELG purposes in the 2014 depreciation study was used as a starting point. Each of the new ASL components were then analyzed to determine if the new component would have a longer or shorter life than the ELG component. In some circumstances, one of the new components represented such a large percentage of investment in the existing account that the larger component has been assigned the same life estimate as the larger ELG component.

The development of the average service life estimates for the IFRS compliant ASL procedure included the following review for each new account:

- Review by Manitoba Hydro Operations staff to provide an indication of the average service life of each of the components;
- Review of the Manitoba Hydro internal estimates by Gannett Fleming;
- Review to determine if the lives for the new components are consistent with the lives as determined for the ELG components in the current depreciation study; and
- The lives of all components were rounded to the nearest 5 years.

The resultant average service life estimates for all new components are identified on the Table of results in Part 3 of this report.

TESTING AND REVIEW

The Gannett Fleming testing was completed in two parts. Firstly, for the investment as of March 31, 2014, Gannett Fleming completed a series of ASL procedure calculations on the increased level of componentization which included the new average service life estimates for each of the components. The ELG calculations were developed in the current depreciation study filed with this application. Secondly, a first year calculation was made for the investment related to the two new capital projects, which required development of detailed depreciation calculations for the ELG and IFRS compliant ASL procedures.

A component of the depreciation rates includes the true-up of accumulated depreciation variances between the level of actual accumulated depreciation balances and the calculated (or theoretical) accumulated depreciation balances. In order to develop the true-up calculations, Gannett Fleming developed an allocation of the accumulated depreciation amounts as of March 31, 2014 for use with the IFRS compliant ASL procedure. For the ELG components, the true up calculations were developed in the current depreciation study.

A table summarizing the results of the analysis is provided in Part 3 of this report.

PART III. RESULTS AND CONCLUSIONS

PART 3. RESULTS AND CONCLUSIONS

RESULTS

Based on the analysis completed by Gannett Fleming on the March 31, 2014 balances, the depreciation expense related to the proposed use of the ELG procedure on the $2.9 billion of original cost is $738,000 higher as compared to the use of the IFRS compliant ASL procedure. Extrapolating the $0.7 million difference to 100% of the March 31, 2014 asset balance equates to an approximately $3.5 million annual difference between the two approaches. However, on the analysis of the forecast Bipole III and Keeyask projects the depreciation expense related to the proposed ELG procedure is $140,000 less than the IFRS compliant ASL procedure. Extrapolating the ($0.1) million difference between the IFRS-compliant ASL method and the ELG method results over the total of the analyzed project additions over the next 10 years, equates to an approximately ($0.7) million annual difference between the two approaches. The results of the Gannett Fleming Analysis is summarized in Table 1 on page III-5 and in more detail by account in Tables 2, 3 and 4 provided at pages III-6, III-7 and III-8 of this report.

Figure 2 - Summary of Differences in Depreciation Procedures

Component	Depreciation Expense ($ millions)		
	ELG Method	ASL Method	Difference
March 31, 2014 Accounts:			
A/C Electrical Power Systems (Generation)	7.16		
- Step-up Transformers Manufactured before 1950		-	
- Step-up Transformers Manufactured in 1950 or later		3.63	
- A/C Electrical Power Systems – Other Equipment		4.35	
Turbines and Generators (Generation)	23.45		
- Turbines		8.80	
- Generators		15.15	
Poles and Fixtures (Transmission)	2.11		
- Wood Poles and Fixtures		1.31	
- Cross-arms		0.42	
Other Transformers (Substations)	2.54		
- Other Transformers		1.61	
- Potential and Current Transformers		0.50	
Interrupting Equipment (Substations)	4.85		
- Other Interrupting Equipment		2.67	
- Vacuum Circuit Breakers		0.73	
- Min Oil and SF6 Breakers		1.09	
- Air Magnetic Breakers		0.44	
- Air Blast and Oil Bulk Breakers		0.09	
Poles and Fixtures (Distribution)	10.59		
- Wood Poles and Fixtures		7.62	
- Cross-arms		1.41	
Buildings (360 Portage)	1.98		
- Electro/mechanical - Finishes		0.73	
- Electro/mechanical – Mechanical/Windows and Other		1.05	
- Electro/mechanical – Millwork and Elevators		0.16	
- Electro/mechanical – Interior Glaze/Drywall and Electrical		0.17	
Sub-Total March 31, 2014 Balances	**52.67**	**51.93**	**0.74**
Capital Expenditure Forecast:			
Synchronous Condensers and Unit Transformers (Bipole III)*	3.66		
- Synchronous Transformers		1.93	
- Unit Transformers		1.68	
Converter Equipment (Bipole III)	14.97		
- HVDC Converter Valves and Valve Cooling Equipment		6.17	
- HVDC Converter Transformers		8.83	
Water Control Systems (Keeyask)**	9.04		
- Water Control Systems		8.15	
- Ice, Debris and Public Safety Booms		0.71	
Turbines and Generators (Keeyask)	9.79		
- Turbines		3.95	
- Generators		6.59	
A/C Electrical Power Systems (Keeyask)	4.77		
- Step-up Transformers Manufactured in 1950 or later		1.03	
- A/C Electrical Power Systems – Other Equipment		3.33	
Sub-Total Forecast Balances	**42.23**	**42.37**	**(0.14)**

* *Assumes Fiscal 2019 when Bipole III is fully in service*
** *Assumes 2021 when Keeyask GS is fully in service*

CONCLUSION

The $738,000 difference based on the accounts tested as of March 31, 2014 between an IFRS-compliant ASL and ELG method demonstrates that compliance with the depreciation requirements of IFRS will result in a similar increase in depreciation expense, regardless of the depreciation method used. In Appendix 5.7 of this application, Manitoba Hydro indicates the estimated annual increase in depreciation expense for complying with IFRS by changing to the ELG method is $36 million. This annual increase in depreciation would be approximately $33 million if Manitoba Hydro were to continue with an IFRS compliant ASL method.

The difference of $140,000 resulting from analysis comparing the impact on the two large new capital projects (Bipole III and Keeyask) also demonstrates the convergence of the depreciation expense between the two methods.

Overall, the testing completed by Gannett Fleming indicates that a similar impact will result when the two methods are applied to a significant level of asset costs (both as of March 31, 2014, and on the two large forecasted capital projects). Gannett Fleming strongly cautions that depreciation expense is an estimate, and that this analysis is on a representative sample basis only and it is possible that the results of a complete study of existing and projected asset additions could be smaller or larger than the balances provided in this analysis. Such differences may also be altered by differences between actual and projected levels of capital expenditures and asset retirements.

Based on the results of the testing presented in this report, Gannett Fleming views that the statements made in the 2013/2014 General Rate Application Proceeding regarding the fact that an IFRS compliant ASL Procedure would result in a similar level of depreciation expense as the proposed change to the ELG procedure have been demonstrated. The over-riding benefit of the proposed ELG procedure is the elimination of the need to undertake a very significant effort to develop the level of componentization required for the use of an IFRS compliant ASL procedure.

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

		FILED ELG								ASL - COMPONENTIZATION							
ACCOUNT	ACCOUNT DESCRIPTION	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Great Falls 1105P A/C Electrical Power Systems:																	
1105P1	Step-Up Transformers Manufactured before 1950									2063	60-R4	163,626	2,733	1.67	(25,260)	(22,527)	(13.77)
1105P2	Step-up Transformers Manufactured in 1950 or later									2063	40-R4	3,811,668	95,292	2.50	(7,877)	87,415	2.29
1105P3	A/C Electrical Power Systems - Other Equipment									2063	55-R4	5,517,794	100,696	1.82	(9,812)	90,884	1.65
1105P	**A/C Electrical Power Systems - Total for Parent Account**	2063	55-R4	**9,493,088**	**178,427**	**1.88**	**(20,168)**	**158,259**	**1.67**			**9,493,088**	**198,721**	**2.09**	**(42,949)**	**155,772**	**1.64**
Point du Bois 1110P A/C Electrical Power Systems:																	
1110P1	Step-Up Transformers Manufactured before 1950																
1110P2	Step-up Transformers Manufactured in 1950 or later									2040	40-R4	6,324,690	211,361	3.34	(42,537)	168,824	2.67
1110P3	A/C Electrical Power Systems - Other Equipment									2040	55-R4	1,435,296	49,693	3.46	(6,326)	43,367	3.02
1110P	**A/C Electrical Power Systems - Total for Parent Account**	2040	55-R4	**7,759,986**	**264,381**	**3.41**	**(48,663)**	**215,718**	**2.78**			**7,759,986**	**261,054**	**3.36**	**(48,863)**	**212,191**	**2.73**
Seven Sisters 1115P A/C Electrical Power Systems:																	
1115P1	Step-Up Transformers Manufactured before 1950									2072	60-R4	348,199	5,815	1.67	(11,285)	(5,470)	(1.57)
1115P2	Step-up Transformers Manufactured in 1950 or later									2072	40-R4	4,455,082	111,377	2.50	(18,944)	92,433	2.07
1115P3	A/C Electrical Power Systems - Other Equipment									2072	50-R4	7,120,950	135,967	1.91	(14,934)	121,033	1.70
1115P	**A/C Electrical Power Systems - Total for Parent Account**	2072	55-R4	**11,924,230**	**223,527**	**1.87**	**(37,834)**	**185,693**	**1.56**			**11,924,231**	**253,159**	**2.12**	**(45,163)**	**207,996**	**1.74**
Slave Falls 1120P A/C Electrical Power Systems:																	
1120P1	Step-Up Transformers Manufactured before 1950									2072	60-R4	960,483	16,328	1.70	(827)	15,501	1.61
1120P2	Step-up Transformers Manufactured in 1950 or later																
1120P3	A/C Electrical Power Systems - Other Equipment									2072	55-R4	20,671,367	382,740	1.85	(13,147)	369,593	1.79
1120P	**A/C Electrical Power Systems - Total for Parent Account**	2072	55-R4	**21,631,850**	**421,951**	**1.95**	**(9,787)**	**412,164**	**1.91**			**21,631,850**	**399,068**	**1.84**	**(13,974)**	**385,094**	**1.78**
Pine Falls 1125P A/C Electrical Power Systems:																	
1125P1	Step-Up Transformers Manufactured before 1950									2092	60-R4	350,135	5,847	1.67	(11,236)	(5,389)	(1.54)
1125P2	Step-up Transformers Manufactured in 1950 or later																
1125P3	A/C Electrical Power Systems - Other Equipment									2092	55-R4	4,746,843	86,393	1.82	(11,299)	75,094	1.58
1125P	**A/C Electrical Power Systems - Total for Parent Account**	2092	55-R4	**5,096,978**	**92,115**	**1.81**	**(11,342)**	**80,773**	**1.58**			**5,096,978**	**92,240**	**1.81**	**(22,535)**	**69,705**	**1.37**
McArthur Falls 1130P A/C Electrical Power Systems:																	
1130P1	Step-Up Transformers Manufactured before 1950									2095	60-R4	319,824	5,341	1.67	(8,255)	(2,914)	(0.91)
1130P2	Step-up Transformers Manufactured in 1950 or later																
1130P3	A/C Electrical Power Systems - Other Equipment									2095	55-R4	2,201,937	40,075	1.82	(9,572)	30,503	1.39
1130P	**A/C Electrical Power Systems - Total for Parent Account**	2095	55-R4	**2,521,761**	**43,075**	**1.71**	**(9,746)**	**33,329**	**1.32**			**2,521,761**	**45,416**	**1.80**	**(17,827)**	**27,589**	**1.09**
Kelsey 1135P A/C Electrical Power Systems:																	
1135P1	Step-Up Transformers Manufactured before 1950																
1135P2	Step-up Transformers Manufactured in 1950 or later									2101	40-R4	15,764,992	394,125	2.50	22,946	417,071	2.65
1135P3	A/C Electrical Power Systems - Other Equipment									2101	55-R4	24,729,522	450,077	1.82	30,199	480,276	1.94
1135P	**A/C Electrical Power Systems - Total for Parent Account**	2101	55-R4	**40,494,515**	**779,913**	**1.93**	**42,291**	**822,204**	**2.03**			**40,494,514**	**844,202**	**2.08**	**53,145**	**897,347**	**2.22**
Grand Rapids 1140P A/C Electrical Power Systems:																	
1140P1	Step-Up Transformers Manufactured before 1950																
1140P2	Step-up Transformers Manufactured in 1950 or later									2091	40-R4	2,957,039	73,926	2.50	(4,628)	69,298	2.34
1140P3	A/C Electrical Power Systems - Other Equipment									2091	55-R4	5,283,506	96,160	1.82	(15,370)	80,790	1.53
1140P	**A/C Electrical Power Systems - Total for Parent Account**	2091	55-R4	**8,240,545**	**153,036**	**1.86**	**(16,600)**	**136,436**	**1.66**			**8,240,545**	**170,086**	**2.06**	**(19,998)**	**150,088**	**1.82**
Kettle 1145P A/C Electrical Power Systems:																	
1145P1	Step-Up Transformers Manufactured before 1950																
1145P2	Step-up Transformers Manufactured in 1950 or later									2111	40-R4	36,244,611	906,115	2.50	24,903	931,018	2.57
1145P3	A/C Electrical Power Systems - Other Equipment									2111	50-R4	2,535,002	50,700	2.00	22,041	72,741	2.87
1145P	**A/C Electrical Power Systems - Total for Parent Account**	2111	55-R4	**38,779,613**	**745,736**	**1.92**	**12,798**	**758,534**	**1.96**			**38,779,613**	**956,815**	**2.47**	**46,944**	**1,003,759**	**2.59**
Laurie River 1150P A/C Electrical Power Systems:																	
1150P1	Step-Up Transformers Manufactured before 1950																
1150P2	Step-up Transformers Manufactured in 1950 or later																
1150P3	A/C Electrical Power Systems - Other Equipment									2035	55-R4	1,441,945	39,580	2.74	3,966	43,546	3.02
1150P	**A/C Electrical Power Systems - Total for Parent Account**	2035	55-R4	**1,441,945**	**40,426**	**2.80**	**4,948**	**45,374**	**3.15**			**1,441,945**	**39,580**	**2.74**	**3,966**	**43,546**	**3.02**
Jenpeg 1155P A/C Electrical Power Systems:																	
1155P1	Step-Up Transformers Manufactured before 1950																
1155P2	Step-up Transformers Manufactured in 1950 or later									2118	40-R4	5,710,258	142,756	2.50	(56,656)	86,100	1.51
1155P3	A/C Electrical Power Systems - Other Equipment									2118	55-R4	15,931,351	289,951	1.82	(30,158)	259,793	1.63
1155P	**A/C Electrical Power Systems - Total for Parent Account**	2118	55-R4	**21,641,608**	**394,933**	**1.82**	**(63,837)**	**331,096**	**1.53**			**21,641,609**	**432,707**	**2.00**	**(86,814)**	**345,893**	**1.60**
Churchill River Diversion 1165P A/C Electrical Power Systems:																	
1165P1	Step-Up Transformers Manufactured before 1950																
1165P2	Step-up Transformers Manufactured in 1950 or later																
1165P3	A/C Electrical Power Systems - Other Equipment										55-R4	1,710,889	31,138	1.82	(6,356)	24,782	1.45
1165P	**A/C Electrical Power Systems - Total for Parent Account**		55-R4	**1,710,889**	**31,121**	**1.82**	**(4,201)**	**26,920**	**1.57**			**1,710,889**	**31,138**	**1.82**	**(6,356)**	**24,782**	**1.45**
Long Spruce 1170P A/C Electrical Power Systems:																	
1170P1	Step-Up Transformers Manufactured before 1950																
1170P2	Step-up Transformers Manufactured in 1950 or later									2118	40-R4	19,424,177	485,604	2.50	9,325	494,929	2.55
1170P3	A/C Electrical Power Systems - Other Equipment									2118	55-R4	11,186,563	203,595	1.82	1,202	204,797	1.83
1170P	**A/C Electrical Power Systems - Total for Parent Account**	2118	55-R4	**30,610,740**	**560,009**	**1.83**	**(99,219)**	**460,790**	**1.51**			**30,610,740**	**689,199**	**2.25**	**10,527**	**699,726**	**2.29**

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

		FILED ELG								ASL - COMPONENTIZATION							
ACCOUNT	ACCOUNT DESCRIPTION	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Limestone 1175P A/C Electrical Power Systems:																	
1175P1	Step-Up Transformers Manufactured before 1950																
1175P2	Step-up Transformers Manufactured in 1950 or later									2131	40-R4	43,746,177	1,093,654	2.50	(99,436)	994,218	2.27
1175P3	A/C Electrical Power Systems - Other Equipment									2131	55-R4	100,842,764	1,835,338	1.82	(94,006)	1,741,332	1.73
1175P	**A/C Electrical Power Systems - Total for Parent Account**	2131	55-R4	**144,588,941**	**2,741,516**	**1.90**	**(233,699)**	**2,507,817**	**1.73**			**144,588,941**	**2,928,992**	**2.03**	**(193,442)**	**2,735,550**	**1.89**
Wuskwatim 1180P A/C Electrical Power Systems:																	
1180P1	Step-Up Transformers Manufactured before 1950																
1180P2	Step-up Transformers Manufactured in 1950 or later									2152	40-R4	403,600	10,090	2.50	(71)	10,019	2.48
1180P3	A/C Electrical Power Systems - Other Equipment									2152	55-R4	1,288,063	23,443	1.82	(118)	23,325	1.81
1180P	**A/C Electrical Power Systems - Total for Parent Account**	2152	55-R4	**1,691,663**	**32,649**	**1.93**	**(192)**	**32,457**	**1.92**			**1,691,663**	**33,533**	**1.98**	**(189)**	**33,344**	**1.97**
Wuskwatim Power Limited Partnership ("WPLP") 1181P A/C Electrical Power Systems:																	
1181P1	WPLP - Step-Up Transformers Manufactured before 1950																
1181P2	WPLP - Step-up Transformers Manufactured in 1950 or later									2152	40-R4	11,907,305	297,683	2.50	(2,902)	294,781	2.48
1181P3	WPLP - A/C Electrical Power Systems - Other Equipment									2152	55-R4	38,001,362	691,625	1.82	(4,846)	686,779	1.81
1181P	**A/C Electrical Power Systems - Total for Parent Account**	2152	55-R4	**49,908,667**	**963,237**	**1.93**	**(7,597)**	**955,640**	**1.91**			**49,908,667**	**989,308**	**1.98**	**(7,748)**	**981,560**	**1.97**
1105G1	Turbines									2063	75-S3	14,949,264	250,605	1.68	16,610	267,215	1.79
1105G2	Generators									2063	45-S3	18,869,048	419,849	2.23	27,659	447,508	2.37
1105G	**Turbines and Generators - Total for Parent Account**	2063	60-S3	**33,818,312**	**647,992**	**1.92**	**39,027**	**687,019**	**2.03**			**33,818,312**	**670,454**	**1.98**	**44,269**	**714,723**	**2.11**
Pointe du Bois 1110G:																	
1110G1	Turbines									2040	75-S3	27,977,470	884,721	3.16	(223,804)	660,917	2.36
1110G2	Generators									2040	45-S3	3,921,590	127,123	3.24	(31,420)	95,703	2.44
1110G	**Turbines and Generators - Total for Parent Account**	2040	60-S3	**31,899,060**	**1,036,836**	**3.25**	**(256,998)**	**779,838**	**2.44**			**31,899,060**	**1,011,844**	**3.17**	**(255,224)**	**756,620**	**2.37**
Seven Sisters 1115G:																	
1115G1	Turbines									2072	75-S3	34,324,616	538,754	1.57	(29,435)	509,319	1.48
1115G2	Generators									2072	45-S3	20,124,707	448,104	2.23	(51,168)	396,936	1.97
1115G	**Turbines and Generators - Total for Parent Account**	2072	60-S3	**54,449,323**	**986,438**	**1.81**	**(64,103)**	**922,335**	**1.69**			**54,449,323**	**986,858**	**1.81**	**(80,603)**	**906,255**	**1.66**
Slave Falls 1120G:																	
1120G1	Turbines									2072	75-S3	5,916,360	92,011	1.56	(488)	91,523	1.55
1120G2	Generators									2072	45-S3	6,330,169	140,617	2.22	(1,131)	139,486	2.20
1120G	**Turbines and Generators - Total for Parent Account**	2072	60-S3	**12,246,529**	**224,685**	**1.83**	**(3,206)**	**221,479**	**1.81**			**12,246,529**	**232,628**	**1.90**	**(1,619)**	**231,009**	**1.89**
Pine Falls 1125G:																	
1125G1	Turbines									2092	75-S3	4,890,684	65,401	1.34	(9,048)	56,353	1.15
1125G2	Generators									2092	45-S3	4,427,470	98,290	2.22	(27,038)	71,252	1.61
1125G	**Turbines and Generators - Total for Parent Account**	2092	60-S3	**9,318,154**	**150,312**	**1.61**	**(22,361)**	**127,951**	**1.37**			**9,318,154**	**163,691**	**1.76**	**(36,086)**	**127,605**	**1.37**
McArthur Falls 1130G:																	
1130G1	Turbines									2095	75-S3	2,902,707	38,684	1.33	(16,087)	22,597	0.78
1130G2	Generators									2095	45-S3	2,476,911	54,987	2.22	(59,614)	(4,627)	(0.19)
1130G	**Turbines and Generators - Total for Parent Account**	2095	60-S3	**5,379,618**	**77,690**	**1.44**	**(27,218)**	**50,472**	**0.94**			**5,379,618**	**93,671**	**1.74**	**(75,701)**	**17,970**	**0.33**
Kelsey 1135G:																	
1135G1	Turbines									2101	75-S3	78,758,820	1,077,668	1.37	26,857	1,104,525	1.40
1135G2	Generators									2101	45-S3	67,625,037	1,501,276	2.22	78,692	1,579,968	2.34
1135G	**Turbines and Generators - Total for Parent Account**	2101	60-S3	**146,383,857**	**2,613,973**	**1.79**	**91,265**	**2,705,238**	**1.85**			**146,383,857**	**2,578,944**	**1.76**	**105,549**	**2,684,493**	**1.83**
Grand Rapids 1140G:																	
1140G1	Turbines									2091	75-S3	60,479,918	821,891	1.36	(22,537)	799,354	1.32
1140G2	Generators									2091	45-S3	52,733,707	1,170,688	2.22	(52,693)	1,117,995	2.12
1140G	**Turbines and Generators - Total for Parent Account**	2091	60-S3	**113,213,625**	**2,003,975**	**1.77**	**(36,364)**	**1,967,611**	**1.74**			**113,213,625**	**1,992,579**	**1.76**	**(75,230)**	**1,917,349**	**1.69**
Kettle 1145G:																	
1145G1	Turbines									2111	75-S3	27,147,622	361,172	1.33	3,205	364,377	1.34
1145G2	Generators									2111	45-S3	72,015,762	1,598,750	2.22	8,311	1,607,061	2.23
1145G	**Turbines and Generators - Total for Parent Account**	2111	60-S3	**99,163,384**	**1,693,671**	**1.71**	**23,758**	**1,717,429**	**1.73**			**99,163,384**	**1,959,922**	**1.98**	**11,516**	**1,971,438**	**1.99**
Laurie River 1150G:																	
1150G1	Turbines									2035	75-S3	371,894	10,496	2.82	613	11,109	2.99
1150G2	Generators									2035	45-S3	4,231,242	147,942	3.50	4,990	152,932	3.61
1150G1	Turbines																
1150G	**Turbines and Generators - Total for Parent Account**	2035	60-S3	**4,603,136**	**160,625**	**3.49**	**6,099**	**166,724**	**3.62**			**4,603,136**	**158,438**	**3.44**	**5,603**	**164,041**	**3.56**
Jenpeg 1155G:																	
1155G1	Turbines									2118	75-S3	47,800,851	637,186	1.33	(2,443)	634,743	1.33
1155G2	Generators									2118	45-S3	43,915,520	974,925	2.22	(14,206)	960,719	2.19
1155G	**Turbines and Generators - Total for Parent Account**	2118	60-S3	**91,716,371**	**1,582,037**	**1.72**	**12,804**	**1,594,841**	**1.74**			**91,716,371**	**1,612,111**	**1.76**	**(16,649)**	**1,595,462**	**1.74**
Long Spruce 1170G:																	
1170G1	Turbines									2118	75-S3	63,342,196	842,451	1.33	(17,270)	825,181	1.30
1170G2	Generators									2118	45-S3	79,986,447	1,775,699	2.22	(93,529)	1,682,170	2.10
1170G	**Turbines and Generators - Total for Parent Account**	2118	60-S3	**143,328,643**	**2,453,827**	**1.71**	**(25,472)**	**2,428,355**	**1.69**			**143,328,643**	**2,618,150**	**1.83**	**(110,799)**	**2,507,351**	**1.75**

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

		FILED ELG								ASL - COMPONENTIZATION							
ACCOUNT	ACCOUNT DESCRIPTION	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Limestone 1175G:																	
1175G1	Turbines									2131	75-S3	180,982,160	2,407,063	1.33	43,437	2,450,500	1.35
1175G2	Generators									2131	45-S3	223,347,469	4,958,314	2.22	199,599	5,157,913	2.31
1175G	**Turbines and Generators - Total for Parent Account**	2131	60-S3	**404,329,629**	**7,181,521**	**1.78**	**134,341**	**7,315,862**	**1.81**			**404,329,629**	**7,365,377**	**1.82**	**243,036**	**7,608,413**	**1.88**
Wuskwatim 1180G:																	
1180G1	Turbines									2152	75-S3	2,279,516	30,318	1.33	(170)	30,148	1.32
1180G2	Generators									2152	45-S3	2,372,558	52,671	2.22	(496)	52,175	2.20
1180G	**Turbines and Generators - Total for Parent Account**	2152	60-S3	**4,652,074**	**83,272**	**1.79**	**(581)**	**82,691**	**1.78**			**4,652,074**	**82,989**	**1.78**	**(666)**	**82,323**	**1.77**
Wuskwatim Power Limited Partnership ("WPLP") 1181G:																	
1181G1	WPLP - Turbines									2152	75-S3	73,430,216	976,622	1.33	(95)	976,527	1.33
1181G2	WPLP - Generators									2152	45-S3	76,427,367	1,696,688	2.22	(278)	1,696,410	2.22
1181G	**WPLP - Turbines and Generators - Total for Parent Account**	2152	60-S3	**149,857,582**	**2,682,451**	**1.79**	**(322)**	**2,682,129**	**1.79**			**149,857,583**	**2,673,310**	**1.78**	**(373)**	**2,672,937**	**1.78**
2000J1	Wood Poles and Fixtures										65-R3	98,335,498	1,514,367	1.54	(204,145)	1,310,222	1.33
2000J2	Crossarms										35-R2	18,730,571	535,694	2.86	(117,120)	418,574	2.23
2000J	**Poles and Fixtures - Total for Parent Account**		55-R3	**117,066,069**	**2,279,899**	**1.95**	**(175,193)**	**2,104,706**	**1.80**			**117,066,069**	**2,050,061**	**1.75**	**(321,265)**	**1,728,796**	**1.48**
3100S1	Other Transformers										45-R1.5	80,244,655	1,781,431	2.22	(169,730)	1,611,701	2.01
3100S2	Potential and Current Transformers										60-S0.5	32,245,815	538,505	1.67	(42,387)	496,118	1.54
3100S	**Other Transformers - Total for Parent Account**		50-S1	**112,490,470**	**2,488,670**	**2.21**	**48,344**	**2,537,014**	**2.26**			**112,490,470**	**2,319,936**	**2.06**	**(212,117)**	**2,107,819**	**1.87**
3100T1	Other Interrupting Equipment										50-R2.5	128,502,890	2,570,058	2.00	104,140	2,674,198	2.08
3100T2	Vacuum Circuit Breakers										20-R2.5	13,442,631	664,282	4.94	68,600	732,882	5.45
3100T3	Min Oil and SF6 Breakers										40-R2.5	41,157,542	1,028,939	2.50	59,529	1,088,468	2.64
3100T4	Air Magnetic Breakers										50-R2.5	18,181,824	363,636	2.00	71,600	435,236	2.39
3100T5	Air Blast and Oil Bulk Breakers										100-R2.5	8,760,820	87,608	1.00	6,290	93,898	1.07
3100T	**Interrupting Equipment - Total for Parent Account**		50-R2.5	**210,045,708**	**4,428,834**	**2.11**	**418,260**	**4,847,094**	**2.31**			**210,045,707**	**4,714,523**	**2.24**	**310,159**	**5,024,682**	**2.39**
4000J1	Wood Poles and Fixtures										65-S1	601,525,314	9,263,490	1.54	(1,648,252)	7,615,238	1.27
4000J2	Crossarms										35-R2.5	67,430,774	1,928,520	2.86	(516,735)	1,411,785	2.09
4000J	**Poles and Fixtures - Total for Parent Account**		65-S0.5	**668,956,088**	**11,903,877**	**1.78**	**(1,315,678)**	**10,588,200**	**1.58**			**668,956,088**	**11,192,010**	**1.67**	**(2,164,987)**	**9,027,023**	**1.35**
Breakdown for Existing Account 8000E - 360 Portage - Electro/Mechanical																	
Account#	**Account Description**																
8000E1	360 Portage - Electro/mechanical - Finishes										20-R2.5	13,901,418	695,071	5.00	30,470	725,541	5.22
8000E2	360 Portage - Electro/mechanical - Mechanical/Windows & Other										40-R3	41,266,289	1,031,657	2.50	21,210	1,052,867	2.55
8000E3	360 Portage - Electro/mechanical - Millwork & Elevators										60-R2	9,262,022	154,676	1.67	1,879	156,555	1.69
8000E4	360 Portage - Electro/mechanical - Interior Glaze/Drywall & Electrical										75-R1.5	12,909,669	171,699	1.33	1,544	173,243	1.34
8000E	**360 Portage - Total for Parent Account**		45-R3	**77,339,398**	**1,937,503**	**2.51**	**39,260**	**1,976,763**	**2.56**			**77,339,398**	**2,053,103**	**2.65**	**55,103**	**2,108,206**	**2.73**
				2,887,794,051	**54,284,140**	**1.88**	**(1,617,187)**	**52,666,953**	**1.82**			**2,887,794,050**	**54,895,817**	**1.90**	**(2,967,360)**	**51,928,457**	**1.80**

Note:
Totals May Not Sum Due To Rounding

MANITOBA HYDRO
TABLE 2. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2019

				FILED ELG					ASL - COMPONENTIZATION				
ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2019	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2019	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel and Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	**1.90**			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment			25 Years										
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	40-50 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000							40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	**2.95**			**507,600,000**	**15,004,500**	**3.00**
Other Components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
	TOTAL BIPOLE III AND KEEYASK FORECAST ADDITIONS					**700,200,000**	**18,633,600**	**2.66**			**700,200,000**	**18,613,740**	**2.66**

* Percentage of Forecast Item for Which Component Breakdown Provided

MANITOBA HYDRO
TABLE 3. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2020

				FILED ELG					ASL - COMPONENTIZATION				
ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel & Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	1.90			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment													
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	25 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000	40-50 Years						40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	2.95			**507,600,000**	**15,004,500**	**3.00**
Other Components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
Keeyask - Future Hydraulic Generating Station													
Manitoba Hydro Owned Assets (Interest Capitalized on MH Equity in KHLP Physical Assets)													
Keeyask 1185E Water Control Systems													
1185E1	Water Control Systems	30,700,000	65 Years						65	R4	21,900,000	337,260	1.54
1185E2	Ice, Debris and Public Safety Booms	1,200,000	30 Years						30	R4	1,200,000	39,960	3.33
		31,900,000		65	R4	**23,100,000**	**378,840**	1.64			**23,100,000**	**377,220**	**2.00**
Keeyask 1185G Turbines and Generators													
1185G1	Turbines	17,200,000	75 Years						75	S3	7,400,000	98,420	1.33
1185G2	Generators	17,200,000	50 Years						45	S3	7,400,000	164,280	2.22
		34,400,000		65	S3	**14,800,000**	**244,200**	1.65			**14,800,000**	**262,700**	**2.00**
Keeyask 1185P A/C Electrical Power Systems													
1185P2	Step-up Transformers Manufactured in 1950 or later	2,400,000	40 Years						40	R4	1,000,000	25,000	2.50
1185P3	A/C Electrical Power Systems - Other Equipment	10,600,000	55 Years						55	R4	4,500,000	81,900	1.82
		13,000,000		50	R4	**5,500,000**	**117,150**	2.13			**5,500,000**	**106,900**	**2.00**
Other Components		**286,000,000**											
CEF14	Keeyask GS - Interest on MH Equity	**365,300,000**											
		22% *											
Keeyask Hydropower Limited Partnership Assets (tangible)													
Keeyask (KHLP) 1186E Water Control Systems													
1186E1	KHLP - Water Control Systems	498,800,000	65 Years						65	R4	356,300,000	5,487,020	1.54
1186E2	KHLP - Ice, Debris and Public Safety Booms	20,200,000	30 Years						30	R4	20,200,000	672,660	3.33
		519,000,000		65	R4	**376,500,000**	**6,174,600**	1.64			**376,500,000**	**6,159,680**	**2.00**
Keeyask (KHLP) 1186G Turbines and Generators													
1186G1	Turbines	279,500,000	75 Years						75	S3	119,800,000	1,593,340	1.33
1186G2	Generators	279,500,000	50 Years						45	S3	119,800,000	2,659,560	2.22
		559,000,000		65	S3	**239,600,000**	**3,953,400**	1.65			**239,600,000**	**4,252,900**	**2.00**

MANITOBA HYDRO
TABLE 3. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2020

				FILED ELG					ASL - COMPONENTIZATION				
ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
Keeyask (KHLP) 1186P A/C Electrical Power Systems													
1186P2	Step-up Transformers Manufactured in 1950 or later	38,800,000	40 Years						40	R4	16,600,000	415,000	2.50
1186P3	A/C Electrical Power Systems - Other Equipment	172,200,000	55 Years						55	R4	73,800,000	1,343,160	1.82
		211,000,000		50	R4	**90,400,000**	**1,925,520**	2.13			**90,400,000**	**1,758,160**	**2.00**
Other Components		**4,639,600,000**											
CEF14	Keeyask GS - Interest on MH Equity	**5,928,600,000**											
		22% *											
	TOTAL PLANT					**1,450,100,000**	**31,427,310**	**2.17**			**1,450,100,000**	**31,531,300**	**2.17**

* Percentage of Forecast Item for Which Component Breakdown Provided

MANITOBA HYDRO
TABLE 4. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2021

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	ELG (AGGREGATE LEVEL - COMPARABLE ACCOUNTS) LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2021	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ASL (COMPONENTIZATION - COMPARABLE SUB-COMPONENTS FOR ACCOUNTS) LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2021	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel & Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	1.90			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment													
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	25 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000	40-50 Years						40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	2.95			**507,600,000**	**15,004,500**	**3.00**
Other components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
Keeyask - Future Hydraulic Generating Station													
Manitoba Hydro Owned Assets (Interest Capitalized on MH Equity in KHLP Physical Assets)													
Keeyask 1185E Water Control Systems													
1185E1	Water Control Systems	30,700,000	65 Years						65	R4	30,700,000	472,780	1.54
1185E2	Ice, Debris and Public Safety Booms	1,200,000	30 Years						30	R4	1,200,000	39,960	3.33
		31,900,000		65	R4	**31,900,000**	**523,160**	1.64			**31,900,000**	**512,740**	**2.00**
Keeyask 1185G Turbines and Generators													
1185G1	Turbines	17,200,000	75 Years						75	S3	17,200,000	228,760	1.33
1185G2	Generators	17,200,000	50 Years						45	S3	17,200,000	381,840	2.22
		34,400,000		65	S3	**34,400,000**	**567,600**	1.65			**34,400,000**	**610,600**	**2.00**
Keeyask 1185P A/C Electrical Power Systems													
1185P2	Step-up Transformers Manufactured in 1950 or later	2,400,000	40 Years						40	R4	2,400,000	60,000	2.50
1185P3	A/C Electrical Power Systems - Other Equipment	10,600,000	55 Years						55	R4	10,600,000	192,920	1.82
		13,000,000		50	R4	**13,000,000**	**276,900**	2.13			**13,000,000**	**252,920**	**2.00**
Other components		**286,000,000**											
CEF14	Keeyask GS - Interest on MH Equity	**365,300,000**											
		22% *											
Keeyask Hydropower Limited Partnership Assets (tangible)													
Keeyask (KHLP) 1186E Water Control Systems													
1186E1	KHLP - Water Control Systems	498,800,000	65 Years						65	R4	498,800,000	7,681,520	1.54
1186E2	KHLP - Ice, Debris and Public Safety Booms	20,200,000	30 Years						30	R4	20,200,000	672,660	3.33
		519,000,000		65	R4	**519,000,000**	**8,511,600**	1.64			**519,000,000**	**8,354,180**	**2.00**

MANITOBA HYDRO
TABLE 4. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2021

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	ELG (AGGREGATE LEVEL - COMPARABLE ACCOUNTS): LIFE SPAN DATE	ELG: SURVIVOR CURVE	ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2021	ELG: CALCULATED ANNUAL ACCRUAL AMOUNT	ELG: CALCULATED ANNUAL ACCRUAL RATE (%)	ASL (COMPONENTIZATION - COMPARABLE SUB-COMPONENTS FOR ACCOUNTS): LIFE SPAN DATE	ASL: SURVIVOR CURVE	ASL: SURVIVING ORIGINAL COST AS OF MARCH 31, 2021	ASL: CALCULATED ANNUAL ACCRUAL AMOUNT	ASL: CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
Keeyask (KHLP) 1186G Turbines and Generators													
1186G1	Turbines	279,500,000	75 Years						75	S3	279,500,000	3,717,350	1.33
1186G2	Generators	279,500,000	50 Years						45	S3	279,500,000	6,204,900	2.22
		559,000,000		65	S3	**559,000,000**	**9,223,500**	1.65			**559,000,000**	**9,922,250**	**2.00**
Keeyask (KHLP) 1186P A/C Electrical Power Systems													
1186P2	Step-up Transformers Manufactured in 1950 or later	38,800,000	40 Years						40	R4	38,800,000	970,000	2.50
1186P3	A/C Electrical Power Systems - Other Equipment	172,200,000	55 Years						55	R4	172,200,000	3,134,040	1.82
		211,000,000		50	R4	**211,000,000**	**4,494,300**	2.13			**211,000,000**	**4,104,040**	**2.00**
Other components		**4,639,600,000**											
CEF14	Keeyask GS - Interest on MH Equity	**5,928,600,000**											
		22% *											
	TOTAL PLANT					**2,068,500,000**	**42,230,660**	**2.04**			**2,068,500,000**	**42,370,470**	**2.05**

* Percentage of Forecast Item for Which Component Breakdown Provided

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May 6, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Gosselin:

RE: Directive 8 and 9 of Order 43/13 re: Average Service Life and Equal Life Group Methods of Depreciation

As part of its 2012/13 & 2013/14 General Rate Application ("GRA"), Manitoba Hydro filed its most recent depreciation study, which included International Financial Rreporting Standards ("IFRS") compliant depreciation rates. Manitoba Hydro will transition to IFRS for its fiscal year beginning April 1, 2015, with comparative information required for the previous fiscal year 2014/15. Upon conversion to IFRS, Manitoba Hydro is moving from the Average Service Life ("ASL") method of depreciation to the Equal Life Group ("ELG") method for finanicial reporting purposes.

On April 26, 2013, the Public Utilities Board ("PUB") issued Order 43/13 with respect to Manitoba Hydro's 2012/13 & 2013/14 GRA. Directives 8 and 9 of this Order are related to the use of the ASL and ELG methods of depreciation, as follows:

> *8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*
>
> *9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

Manitoba Hydro is of the view that the ELG methodology will produce an equivalent annual depreciation expense as compared to an IFRS compliant ASL methodology applied to more asset components.

To respond to Directives 8 and 9 of Order 43/13, Manitoba Hydro has developed an approach that will provide a comparison of the two IFRS compliant depreciation methodologies in the timeframe directed given the size of its property, plant and equipment (approximately $19 billion as at March 31, 2014). As part of this approach, Manitoba Hydro will first develop new asset component groups for each significant asset category (eg. generation, transmission, sub-stations) consistent with an IFRS compliant ASL methodology. The expanded list of asset component groups will be applied to a representative sample of physical facilities. Historical asset records will be analyzed for the selected sample in order to allocate vintaged asset costs and historical retirements between the existing and new components. The results of the asset re-componization from the selected sample will then be extrapolated to the entire asset category.

In developing the IFRS compliant ELG methodology, Manitoba Hydro required approximately two years to review the past 70 years of historical work to be in a position to quantify and vintage the existing asset costs that were allocated between new and existing components. An IFRS compliant ASL method will require additional component groups, and as such the effort required will be significant. By extrapolating the results of a representative sample over each asset category, Manitoba Hydro will be in a position to respond to the directive by Manitoba Hydro's next GRA.

Rather than replicating a full depreciation study, this approach will identify additional asset components for each asset category, which will then be used to produce a set of IFRS compliant ASL depreciation rates that will be used to provide a comparison to the ELG depreciation expense, as sought in Directives 8 and 9 of Order 43/13.

For example, additional components will be identified for hydro electric generating stations. A representative sample of generating station assets will then be selected, analyzed and re-componentized. A representative sample of generating stations would include an older plant, mid-life plant, and a newer plant, such as Wuskwatim. The total cost for each new and existing component will be determined for each representative sample through a review of historic asset records in order to allocate vintaged asset costs and historical retirements between the existing and new components. The total cost by asset component group will be determined by extrapolating the results of the analysis performed on the selected sample for each of the additional generating stations, resulting in the total original cost as of March 31, 2013 being re-allocated to a new set of asset component groups for all generating stations. New depreciation rates will be determined for the new components, and an annual expense impact will be estimated for all generating stations. The annual total depreciation expense for generating stations under the IFRS compliant ASL methodology will then be compared to the annual total depreciation expense under the ELG methodology. This procedure will be performed for each significant asset category and will provide the PUB with a realistic comparison of the differences in depreciation expense between the two IFRS compliant methodologies.

Manitoba Hydro has engaged Gannett Fleming to perform this work. The cost to engage Gannett Fleming for this purpose is expected to be $225,000 including disbursements.

Should you have any questions, please contact the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent Czarnecki
Barrister & Solicitor

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July 8, 2014

Mr. Brent Czarnecki
Law Department
Manitoba Hydro
22nd floor
360 Portage Avenue
Winnipeg MB R3C 0G8

Dear Mr. Czarnecki:

RE: Directive 8 & 9 of Order 43/13
Average Service Life (ASL) and Equal Life Group (ELG) Methods of Depreciation

In Order 43/13, dated April 26, 2013, the Board did not approve Manitoba Hydro's (MH's) proposed change to the ELG method of depreciation for rate setting purposes. In that Order the Board expressed concern that not enough information had been provided to assess the financial consequences on ratepayers, of a change to the ELG method. To address that deficiency, the Board issued Directives 8 & 9 of Order 43/13:

8. *That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*

9. *That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology(without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

From Manitoba Hydro's May 6, 2014 letter, (a copy of which is attached) the Board understands that Manitoba Hydro has proposed meeting the above directives by developing new asset component groups for each significant asset category consistent with an IFRS compliant ASL Methodology. This expanded list of asset component groups will then be applied to a representative sample of physical facilities.

The results of the asset re-componentization from the selected sample will then be extrapolated to the entire asset category. Rather than replicating a full depreciation study, this approach will identify additional asset components for each asset category. Manitoba Hydro will produce a set of IFRS compliant ASL depreciation rates that will be used to provide a comparison to the ELG depreciation expense.

The Board has not approved Manitoba Hydro's change to the use of the ELG methodology for rate-setting purposes. The depreciation methodology is expected to be addressed in Manitoba Hydro's next General Rate Application (GRA), to be filed later this year or early in 2015. To that end, the Board expects that to meet Directives 8 and 9 of Order 43 /13, Manitoba Hydro will file its GRA with fully IFRS compliant ASL based depreciation rates and schedules (that can be compared to fully IFRS compliant ESL based depreciation rates and schedules). The Board will expect Manitoba Hydro to file sufficient evidence to support the implementation of IFRS compliant ASL based depreciation rates (if so Ordered by the Board) for rate-setting purposes.

The Board will also expect Manitoba Hydro to provide a concise comparative analysis of the impact of Major new Generation and Transmission investments (including Wuskwatim G.S.; Bipole III; Keeyask G.S. and 750 Interconnection and GNTL) on future depreciation expense utilizing both the ELG methodology (without net salvage) and the ASL methodology (without net salvage) based on fully IFRS compliant ASL methodology rates.

The specifics of the engagement of external consultants by Manitoba Hydro, if required, are to be determined by Manitoba Hydro so as to be in a position to provide the Board with the required evidence as indicated above.

Sincerely,

"Original Signed By"

Kurt Simonsen, P. Eng.
Associate Secretary

KS/nac

c.c. Mr. Bob Peters, Board Counsel
Mr. Roger Cathcart, Board Advisor
Mr. Greg Barnlund, Manitoba Hydro
Interveners of Record, 2013/14 GRA and NFAT Review

Manitoba Hydro

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October 22, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

RE: Directives 8 and 9 of Order 43/13 re: Average Service Life and Equal Life Group Methods of Depreciation

On May 6, 2014, Manitoba Hydro filed a letter with the Public Utilities Board of Manitoba ("PUB") providing an update in response to Directives 8 and 9 of Order 43/13. These directives required Manitoba Hydro to file updated depreciation rates based on an International Financial Reporting Standards ("IFRS") compliant Average Service Life ("ASL") methodology, and to file a comparison of the impact on the Corporation's Integrated Financial Forecast of using the ASL methodology versus the Equal Life Group ("ELG") method of depreciation. In its letter, Manitoba Hydro indicated that it has developed a representative sampling approach that would provide a comparison of the two IFRS compliant depreciation methodologies in time for Manitoba Hydro's next General Rate Application ("GRA").

By letter of July 8, 2014, the PUB indicated that to meet Directives 8 and 9 of Order 43/13, it expects Manitoba Hydro to file its next GRA with fully IFRS compliant ASL depreciation rates and schedules that can be compared to fully IFRS compliant ELG depreciation rates and schedules.

As the PUB is aware, upon conversion to IFRS, Manitoba Hydro is moving from the ASL method of depreciation to the ELG method for financial reporting purposes. Manitoba Hydro understands that the PUB has not yet accepted the use of the ELG methodology for rate-setting purposes, and that the PUB is seeking additional information in order to assess the impact of the change in methodology on ratepayers.

As noted in its May 6, 2014 letter, in developing IFRS compliant ELG rates, Manitoba Hydro required approximately two years to review the past 70 years of historical asset records to be in a position to quantify and vintage the existing asset costs that were allocated between new and existing asset components. An IFRS compliant ASL method would require the development of additional asset component groups, which would entail a similar effort in time (i.e. two years) and resources to complete. As such, Manitoba Hydro will not be in a position to complete a full depreciation study based on an IFRS compliant ASL methodology in time for the next GRA.

In order to provide the PUB with information to assess the financial impact of the change in depreciation methodology in time for the next GRA, Manitoba Hydro has proposed a representative sampling approach. This approach would identify additional asset components for each significant asset category as would be required for an IFRS compliant ASL methodology; recognizing that the existing Canadian Generally Accepted Accounting Principles ("CGAAP") asset component groupings are not sufficient for an IFRS compliant ASL methodology. For the sample selected, Manitoba Hydro will develop IFRS compliant ASL depreciation rates. The resultant impacts from using these depreciation rates would then be extrapolated to produce a comparison of the annual depreciation expense between the IFRS compliant ASL and ELG methodologies. Manitoba Hydro believes that this analysis would support the move to the ELG methodology for rate setting purposes.

In the event that the PUB determines that the ELG method should not be used for rate-setting purposes, Manitoba Hydro could continue to use the existing CGAAP ASL depreciation rates for setting customer rates. However, in consideration of Manitoba Hydro's existing asset component structure, Manitoba Hydro is adopting the ELG method for IFRS compliant financial reporting purposes (as opposed to rate setting purposes). In this circumstance, Manitoba Hydro would be required, for financial reporting purposes, to establish a rate-regulated account to capture the difference between depreciation expense recorded for rate-setting purposes (existing CGAAP ASL methodology) and depreciation expense that will be recorded for financial reporting purposes (ELG methodology). The approach to capture the differences in a rate-regulated account is an interim measure for rate-setting purposes and would subsequently have to be re-examined at a future GRA.

In an effort to further the mutual understanding between Manitoba Hydro and the PUB on these technical financial issues, Manitoba Hydro is prepared to meet with the PUB's technical financial/accounting advisor. Should you have any questions, please contact the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent Czarnecki
Barrister & Solicitor

cc. Mr. R. Cathcart, Cathcart Advisors Inc.

WPLP Agreement Changes (Directive 11, Order 43/13)

11. That Manitoba Hydro file with the Board any negotiated agreements or changes with respect to the Wuskwatim Power Limited Partnership when finalized, and detail the impacts on Manitoba Hydro's operating results and rates.

Status: Complete

Manitoba Hydro and Nisichawayasihk Cree Nation ("NCN") have recently concluded negotiations and signed the Wuskwatim Project Development Agreement (PDA) Second Supplementary Agreement (Supplement #2) on April 16, 2015 and is effective April 1, 2014. The original PDA was executed in 2006 and the first PDA supplementary agreement was signed in 2011. Two supplemental agreements were required due to significant and evolving changes to Wuskwatim Power Limited Partnership's financial forecast, primarily due to lower than expected export prices and higher capital costs. The changes in forecasts since 2006 resulted in a deferral and reduction in distributions to Partners, and consequently, higher TPC and NCN loan balances. The two supplements were negotiated to ensure that NCN will benefit from the Wuskwatim project which is consistent with the intent and spirit of the original arrangement. Although lower than anticipated when the PDA was ratified in 2006, the income benefits will provide a long-term source of revenue for NCN.

As noted in IFF14 at page 13, the projected net impact to Manitoba Hydro of the terms of Supplement #2 averages approximately $15 million per year over the 20-year forecast period compared to the 2006 PDA terms. The $15 million is about 1% of the 2015/16 and 2016/17 total projected domestic electricity revenues of $1.512 and $1.578 billion, respectively. Over time, the $15 million net income impact will be about 0.4% of projected domestic revenues of $3.344 billion by the end of IFF14 in 2033/34.

The impacts on MH14 net income are explained as follows:

- Reductions in accrued interest income on NCN loans receivable which increases finance expense;
- Accretion of the obligation related to the annual payments from Manitoba Hydro which increases finance expense;
- Amortization of the obligation related to the annual payments from Manitoba Hydro which increases depreciation & amortization expense;
- Reductions in non-controlling interest due to the potential dilution in NCN ownership interest as a result of the elimination of operating cash call advances available; and
- Amendments to the WPLP pricing formula to a weighted average of domestic and export unit sales which increases WPLP revenues and reduces the net losses (or increases net income).

A reduction in WPLP net losses reduces the non-controlling interest that is attributed to TPC and as a result reduces Manitoba Hydro's net income.

The detailed impacts to MH14 net income are shown in the following table:

($Millions)

	Finance Expense	Depreciation & Amortization	Capital & Other Taxes	Non-Controlling Interest	Total Impact to MH14 Net
2015	(3)	(1)	(0)	(13)	(16)
2016	(5)	(1)	(0)	(10)	(16)
2017	(3)	(1)	(0)	(10)	(13)
2018	(4)	(1)	(0)	(9)	(15)
2019	(5)	(1)	(0)	(8)	(14)
2020	(6)	(1)	(0)	(8)	(15)
2021	(8)	(1)	(0)	(9)	(18)
2022	(9)	(1)	(0)	(8)	(18)
2023	(9)	(1)	(0)	(9)	(18)
2024	(11)	(1)	(1)	(6)	(18)
2025	(12)	(1)	(1)	0	(13)
2026	(13)	(1)	(1)	(0)	(15)
2027	(13)	(1)	(1)	0	(14)
2028	(14)	(1)	(1)	1	(14)
2029	(17)	(1)	(1)	1	(18)
2030	(15)	(1)	(1)	2	(15)
2031	(15)	(1)	(1)	2	(14)
2032	(16)	(1)	(1)	3	(14)
2033	(16)	(1)	(1)	3	(14)
2034	(17)	(1)	(1)	4	(14)
Average					(15)

The table in Attachment A provides a summary comparison of terms between Supplement #2, the 2006 PDA and the 2011 Supplement. The response to PUB/MH-I-36b has also been revised to explain the changes to the agreements.

Under Supplement #2, cash flows to NCN over the next 25 years are projected to be approximately $160 million, including $10 million for 2014, $8 million for 2015, and approximately $6 million per year thereafter until all of NCN loans payable to Manitoba Hydro have been repaid in approximately 30 to 35 years. This cash flow includes repayable dividend advances from Manitoba Hydro, water rental relief payments from the Province, coupon payments on the $40 million principal of NCN's Nisi Trust bond, and annual payments of $2.5 million from Manitoba Hydro.

Based on the WPLP financial projections at the time of the 2006 PDA ratification, NCN's average projected annual cash flows were slightly greater than $7 million per year over the same 25 year period. Under MH14 assumptions and the same 2006 PDA terms results in average projected cash flows to NCN which are slightly greater than $2 million per year over the same 25 year period.

NCN has undertaken extensive community consultations regarding the negotiations over the past two years and will be making their final presentations to community members in the coming weeks. A community ratification is not required to conclude Supplement #2.

The Second Supplementary Agreement and tracked-change versions of the Amended and Restated TPC Financing, NCN Financing, Limited Partnership and Power Purchase Agreements can be found in Appendix 11.50 to Tab 11.

Agreement	Provision	2006 PDA	2011 Supplement	2015 Supplement #2
Supplement #2	Refinance $40 million Nisi Trust bond	n.a.	n.a.	At market coupon rates for terms 10 to 30 years
Supplement #2	Adjustment to NCN's projected return	n.a.	Approximately $1 million for 10 years	$2.5 million for 20 years
TPC Financing Agreement	Final investment closing	June 29, 2012 (Final Close)	July 3, 2013	March 31, 2015
TPC Financing Agreement	Maximum Equity Loans	< 4 times TPC invested cash and < 22% of partner total equity	< 6 times TPC invested cash and < 24% of partner total equity	TPC invested cash of $22 million and equity loans up to 33% of total equity ($88million)
TPC Financing Agreement	Operating cash calls	To maintain 85:15 for 1st ten years, 75:25 thereafter	No change from 2006 PDA	Debt/equity operating cash calls at discretion of WPLP Board
TPC Financing Agreement	Operating cash call loans to TPC	Yes	No change from 2006 PDA	No, if TPC unable contribute, then ownership interest diluted
TPC Financing Agreement	Equity loan interest rate premiums	1% during construction & 1st ten years; 3% thereafter	No change from 2006 PDA	0%
NCN Financing Agreement	Dividend advance loan interest rate premiums	3% from 1st advance to Maturity Date	No change from 2006 PDA	0%
NCN Financing Agreement	Increase advance available in 2014 & 2015	n.a.	No change from 2006 PDA	Total cash flow to NCN up to $10 million in 2014 and up to $8 million in 2015 after all other cash payments to NCN
Power Purchase Agreement	Revenue Pricing Formula	Average export transactions	No change from 2006 PDA	Adjusts the pricing formula for the 1st ten years to be the weighted average of domestic

Agreement	Provision	2006 PDA	2011 Supplement	2015 Supplement #2
				and export transactions and then reverts back to average of export transactions
Power Purchase Agreement	Marketing Risk Fee	3%	No change from 2006 PDA	0% until TPC equity loans repaid, then 36% thereafter
Power Purchase Agreement	Excess Spill Revenue Adjustment	n.a.	n.a.	Calculated WPLP revenue loss based on reduced generation at Wuskwatim due to spill at Missi to benefit system as a whole in excess of projected spill at 2006 ratification
2011 Supplementary Agreement	Preferred Distribution Option	n.a.	Preferred minimum distribution (30 year bond rate less 1.5%) Or Preferred participating distribution: 3.1% of adjusted gross revenues (AGR) <$175 million; 4.7% of AGR $175-$475 million; and 6.3% of AGR >$475 million	n.a. (option stale-dated as NCN did not deliver preferential distribution notice at final close)
2011 Supplementary Agreement	Operational Jobs	n.a.	Implementation under negotiation	Implementation under negotiation

n.a. = not applicable

THIS SECOND SUPPLEMENTARY AGREEMENT dated as of March 31, 2015.

BETWEEN:

NISICHAWAYASIHK CREE NATION

(hereinafter referred to as "**NCN**")

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD

(hereinafter referred to as " **Hydro**")

- and -

TASKINIGAHP POWER CORPORATION

(hereinafter referred to as "**TPC**")

- and -

5022649 MANITOBA LTD.

(hereinafter referred to as the "**General Partner**")

- and -

WUSKWATIM POWER LIMITED PARTNERSHIP

(hereinafter referred to as the "**Limited Partnership**")

(together the "**Parties**")

PREAMBLE

WHEREAS:

A. **NCN** and **Hydro**, among others, entered into a Trust Indenture effective March 18, 1996 as part of the arrangements between NCN, Hydro and others to resolve outstanding issues involving the Northern Flood Agreement ("the 1996 Agreement") pursuant to which **Hydro**, among other things, issued a bond in the principal amount of forty million ($40,000,000) dollars to be held by **Nisichawayasihk Trust** in accordance with the **Trust Indenture** ("the Original Bond");

B. The Original Bond was sold and reinvested and **NCN** and **Hydro** subsequently entered into an agreement dated November 28, 2013 (the "**One-Year Agreement**") to provide for interim arrangements while the **Parties** concluded the negotiation of this agreement, including, among other things, an extension of the maturity date of the reinvested bond to December 31, 2014;

C. As of December 31, 2014, the forty million dollar ($40,000,000) principal of the reinvested bond has been invested in four bonds of ten million dollars ($10,000,000) each issued by **Hydro**, with maturities of ten, fifteen, twenty and twenty-five years, respectively (together the "**Hydro Bonds**" and each separately a "**Hydro Bond**");

D. The **Parties** entered into the Wuskwatim Project Development Agreement on June 26, 2006 (the "**PDA**") which was supplemented and amended by the Wuskwatim Project Development Supplementary Agreement made among the **Parties** to this agreement and dated March 15, 2011 ("the **PDA Supplement No. 1**"), together being referred to in this agreement as the "**Amended PDA**";

E. The **Parties** have identified the need for further amendments to the **Amended PDA** and certain related agreements that are schedules to the **Amended PDA** to maintain harmonious relationships between them, their continued joint participation in the Project, and short and long-term benefits for **NCN** from the Project;

F. The **PDA** authorizes Chief and Council by written agreement between the **Parties** to make revisions or amendments to the **PDA** which Chief and Council in its discretion considers advisable or appropriate as long as there is no material and substantial change to the development or operation of the Wuskwatim Project; and

G. To maintain ownership of thirty-three percent (33%) of the Units in the **Limited Partnership**, **TPC** invested twenty-one million one hundred seventy-eight thousand dollars ($21.178 Million) of TPC's Own Invested Cash in the **Limited Partnership** by January 1, 2015, which investment includes a credit from the **Limited Partnership** in favour of **TPC** in the amount of $750,000 (the "**Asset Credit**") and which credit has been accepted by **NCN** in lieu of the transfer by the **Limited Partnership** to **NCN** of a mobitel and trailer pursuant to Section 7.0 of the **One-Year Agreement**.

NOW THEREFORE the **Parties** agree as follows:

ARTICLE 1- GENERAL

1.1 Amended PDA Definitions and Interpretation

Unless otherwise defined in this **PDA Supplement No. 2**, words in bold shall have the same definitions as set out in the **Amended PDA** and the interpretation principles in Article 1 of the **Amended PDA** shall apply to the interpretation of this **PDA Supplement No. 2**.

1.2 PDA Supplement No. 2 Definitions

"**Business Day**" means any day on which **Hydro's** head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba.

"**Nisichawayasihk Trust**" means the trust established pursuant to the Nisichawayasihk Trust Indenture and includes any amalgamated or replacement trust;

"**Nisichawayasihk Trust Indenture**" means the trust indenture dated March 18, 1996 between **NCN**, **Hydro** and others;

"**One-Year Agreement**" means the agreement dated November 28, 2013 made between **NCN** and **Hydro**;

"**PDA Supplement No. 1**" means the Wuskwatim Project Development Supplementary Agreement made between **NCN**, **Manitoba Hydro**, **TPC** the **General Partner** , and **WPLP** dated March 15, 2011;

"**PDA Supplement No. 2**" means this agreement which amends the **PDA** and the **PDA Supplement No. 1**.

ARTICLE 2 - HYDRO BOND

2.1 Hydro Bonds

As long as the Wuskwatim Project continues to generate hydro electricity **Nisichawayasihk Trust** shall, subject to Section 2.2, be entitled to maintain its investment of up to an aggregate capital amount of up to $40 million in the **Hydro Bonds**, and reinvest the principal amount of each **Hydro Bond** upon maturity of that **Hydro Bond** in one or more replacement bonds issued by **Hydro** (together the "**Replacement Hydro Bonds**" and individually a "**Replacement Hydro Bond**"). (For purposes of reinvestment on maturity, a **Replacement Hydro Bond** will be considered to be a **Hydro Bond** under this Section 2.1.)

2.2 Cabinet Approval

The **Parties** acknowledge that the issuance of a **Replacement Hydro Bond** by **Hydro** is subject to approval by the Lieutenant Governor in Council pursuant to *The Manitoba Hydro Act*, as may be amended from time to time. On receipt of notice under Section 2.4, **Hydro** shall act diligently and in a timely manner in seeking all necessary approvals to permit the requested issuance.

2.3 Terms of Replacement Bond

The terms and conditions of each **Replacement Bond** will incorporate the following:

(a) interest will be payable semi-annually on June 30 and December 31 of each year prior to and including maturity, at an interest rate determined in accordance with Section 2.6 and expressed as a percentage per annum;

(b) interest will not accrue after maturity;

(c) **Hydro** will maintain a register of the name and address of the registered holder of the **Replacement Bond** at its head office in the City of Winnipeg, Manitoba, Canada

(d) the **Replacement Bond** is non-transferable, non-assignable, and non-negotiable;

(e) the **Replacement Bond** is non-redeemable unless mutually agreed to be otherwise;

(f) the **Replacement Bond** is repayable for its full principal upon maturity; and

(g) the **Replacement Bond** will rank equally with all other debt obligations of **Manitoba Hydro**.

2.4 Notice of Reinvestment

After consulting with the **Nisichawayasihk Trust** trustees, NCN shall provide **Hydro** with written notice of its intention to reinvest the principal of a maturing Hydro Bond or Replacement Hydro Bonds as the case may be, the amount of the reinvestment and the desired maturity date of the Replacement Hydro Bond not less than one hundred twenty (120) days' prior to the maturity date of the **Hydro Bond** or of a **Replacement Hydro Bond.**

2.5 **Tranches**

Any investment by **Nisichawayasihk Trust** in **Replacement Hydro Bonds** pursuant to this Article 2 may be made in tranches, having different maturity dates, provided that the amount of each tranche shall be a whole multiple of ten million dollars ($10,000,000.00), and that the term of any **Replacement Hydro Bond** shall be for a term of not more than thirty (30) years with its maturity date being a **Hydro Business Day**.

2.6 **Interest**

The interest rate payable to **Nisichawayasihk Trust** on a **Replacement Hydro Bond** will be determined by the middle quote of three bid price quotes, for a marketable bond of **Hydro** guaranteed by the Province of Manitoba, having the same interest rate and maturity date as the **Replacement Hydro Bond** and including any provincial guarantee fee payable to the Province of Manitoba at that time. The bid price quotes will be supplied in writing by three investment dealers used by the Province of Manitoba to underwrite its securities. The interest rate for each new **Replacement Hydro Bond** will be set by **Hydro** five (5) business days prior to the maturity of an existing **Hydro Bond** or **Replacement Hydro Bond**, as the case may be.

2.7 **Non-Revolving**

Any proceeds of a **Hydro Bond** on its maturity that is not reinvested by **Nisichawayasihk Trust** in a **Replacement Hydro Bond** shall not be eligible for investment in a **Replacement Hydro Bond** at any later date and the aggregate amount that may be invested in **Hydro Bonds** under Section 2.1 shall be reduced by that amount.

ARTICLE 3 - AMENDMENTS TO SUPPLEMENT AGREEMENT NO. 1

3.1 **Amendments to Supplement No. 1:**

Articles I, II, and IV and Schedules 4-1 and 4-2 of PDA Supplement No. 1 are of no further force and effect as of March 31, 2015.

ARTICLE 4- AMENDED AND RESTATED POWER PURCHASE AGREEMENT

4.1 **Amendments to Power Purchase Agreement:**

The Power Purchase Agreement is replaced by the Amended and Restated Power Purchase Agreement attached hereto as Schedule 4.1, effective April 1, 2014.

ARTICLE 5 - AMENDMENTS TO WUSKWATIM PDA

5.1 **Amendments to Amended PDA**

The **PDA** is amended by:

(a) revising the definitions in Section 1.2, as follows:

(i) by adding:

"**Excess Spill Energy Review**" means a review of the methodology and assumptions for determining the CRD Wuskwatim Spill Energy and Spill Energy Revenue Adjustment calculations under the Power Purchase Agreement conducted in accordance with Article XVII of this PDA.

(ii) deleting and replacing the definition of Final Closing Date with:

"**Final Closing Date**" means June 29, 2012.

(iii) by adding:

"**Final Investment Date**" means January 1, 2015.

(iv) by adding:

"**Third Limited Partnership Agreement**" means the amended and restated Second Limited Partnership Agreement;

(v) by adding:

"**Second NCN Financing Agreement**" means the amended and restated NCN financing agreement effective April 1, 2014.

(vi) by adding:

"**Second Power Purchase Agreement**" means the amended and restated power purchase agreement effective April 1, 2014.

(vii) by adding:

"**Second TPC Financing Agreement**" means the amended and restated TPC financing agreement effective April 1, 2014.

(viii) by adding the word "First" in front of the words "NCN Financing Agreement", "Power Purchase Agreement" and "TPC Financing Agreement" and the word "Second" in front of the words "Limited Partnership Agreement";

(ix) by deleting the definition of "NCN Loan Agreements" and replacing it with:

"**NCN Loan Agreements**" means the First TPC Financing Agreement and the First NCN Financing Agreement both dated June 28, 2006 which remained in effect up to and including March 31, 2015 and thereafter the Second TPC Financing Agreement and the Second NCN Financing Agreement;

(b) by adding in the ninth line of Section 3.2 after the word "one" the words "third of the number of directors from time to time";

(c) by deleting in Section 4.2 the words "Subject to the Debt Ratio and except as otherwise contemplated by this PDA or by the Limited Partnership Agreement, twenty-five percent (25%) of the Capital Requirements will be funded by equity and seventy-five percent (75%) will be funded by debt";

(d) by deleting in Section 4.8 the words "Subject to section 4.9"; by deleting Section 4.9, Debt Ratio;

(e) by changing in Sections 5.1, 5.2, 5.3, 5.4, 5.5, 5.6, 5.7, 5.9 "TPC Financing Agreement" to "First TPC Financing Agreement";

(f) by deleting Section 5.8, Cash Call Credit Facility and deleting the phrase "and the Cash Call Credit Facility" in the second line of Section 5.15

(g) by changing in Sections 5.10, 5.11 and 5.12 "TPC Financing Agreement" to "Second TPC Financing Agreement";

(h) by changing in Sections 5.13 "NCN Financing Agreement" to "Second NCN Financing Agreement";

(i) by adding "Excess Spill Energy Reviews" after "Transaction Rate Reviews" in Section 17.1;

(j) by adding "any amendments thereto" after "Power Purchase Agreement" in the third line of Section 17.2;

(k) by adding the following as Section 17.18:

Excess Spill Energy Review

17.18 Unless waived by **NCN** and Hydro, once in every five year period during the Term of the Power Purchase Agreement, commencing with the five year period ending on the year-end for the Hydro Financial Year occurring five years after the Final Investment Closing, provided there has not been an Excess Spill Energy Review within the immediately two preceding years, either Hydro or **NCN**, upon written notice given to the other party, may cause an Expert to be appointed pursuant to section 17.15, to review the Spill Energy Revenue Adjustment under the Power Purchase Agreement and provide non-binding recommendations as to what changes, if any, any required to the CRD Wuskwatim Spill Energy and the Spill Energy Revenue Adjustment (as defined in the Power Purchase Agreement) and any related matters as set out in Article 9 of the Power Purchase Agreement.

(l) by adding the following as Section 17.19:

Process for Spill Energy Rate Review

17.19 Sections 17.7, 17.8, 17.9, 17.13, 17,.14, 17.15, 17. 16 and 17.17 shall apply with any necessary modifications to any Spill Energy Rate Review;

ARTICLE 6- AMENDED AND RESTATED NCN FINANCING AGREEMENT

6.1 **Amendments to the NCN Financing Agreement:**

The **NCN Financing Agreement** is replaced by the Amended and Restated NCN Financing Agreement attached hereto as Schedule 6.1 effective April 1, 2014.

ARTICLE 7- AMENDED AND RESTATED TPC FINANCING AGREEMENT

7.1 **Amendments to TPC Financing Agreement:**

The **TPC Financing Agreement** is replaced by the Amended and Restated TPC Financing Agreement attached hereto as Schedule 7.1 effective March 31, 2015.

ARTICLE 8- AMENDED AND RESTATED LIMITED PARTNERSHIP AGREEMENT

8.1 **Amendments to the Second Amended and Restated Limited Partnership Agreement:**

The **Second Limited Partnership Agreement** is replaced by the Third Amended and Restated Limited Partnership Agreement attached hereto as Schedule 8.1 effective March 31, 2015.

ARTICLE 9 - AMENDMENTS TO PROJECT FINANCING AGREEMENT

9.1 **Amendments to Project Financing Agreement:**

The **Project Financing Agreement** is amended by deleting Section 8.3 "Financial Covenants" and replacing it with the following:

> 8.3 **Financial Covenants.**
>
> So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Credit Facility Commitment under this Agreement, unless Hydro shall otherwise consent, the Limited Partnership agrees that no Distributions shall be made which shall cause the Debt Ratio to exceed 75%.

ARTICLE 10 - CREDIT FOR ASSETS

10.1 In lieu of the transfer by the **Limited Partnership** to **NCN** of a mobitel and trailer pursuant to Section 7.0 of the **One-Year Agreement**, **NCN** acknowledges receipt of the **Asset Credit** made by the **Limited Partnership** to **TPC's** capital account, which amount the **Parties** agree forms part of **TPC's Invested Cash** totalling twenty-one million one hundred seventy-eight thousand dollars ($21,178,000.00) as of December 31, 2014.

ARTICLE 11 - HYDRO ANNUITY

11.1 **Hydro Annuity.**

(a) Provided that **TPC** has not exercised a **TPC Sale Right**, upon execution of this **PDA Supplement No. 2**, in accordance with the **Deed of Assignment Hydro** shall pay **Taskinigahp Trust** the sum of three million one hundred twelve thousand one hundred thirteen dollars ($3,112,113.00).

(b) For so long as **TPC** maintains a minimum investment as **a Limited Partner** in the **Limited Partnership** of not less than twenty-one million one hundred seventy-eight thousand dollars ($21,178,000.00) in **TPC's Own Invest Cash, Hydro** shall pay to **NCN** the sum of two million five hundred thousand dollars ($2,500,00.00) per annum on the first day of January in each year commencing January 1 2016, and continuing to and including January 1, 2033.

ARTICLE 12 - GENERAL AND TRANSITIONAL PROVISIONS

12.1 **General**

(a) Applicable Law

This **PDA Supplement No. 2** will be interpreted, implemented and enforced in accordance with the laws in force in the Province of Manitoba.

(b) Notices

Any notice or other communication pursuant to this **PDA Supplement No. 2** will be in writing, and given in accordance with Section 26.2 of the **Amended PDA**.

(c) Enurement

This **PDA Supplement No. 2** will endure to and be binding upon the successors and any permitted assigns of the **Parties**.

(d) Arbitration

In the event of a dispute arising under or in relation to this **PDA Supplement No. 2**, the dispute resolution process under Article XXI of the **Amended PDA** will apply.

12.2 **Amendment Process**

The **Parties** agree that the amendments in this **PDA Supplement No. 2** do not materially or substantially change the arrangements between them with respect to the operation of the Wuskwatim Project which was developed pursuant to the terms of the **Amended PDA** and has been commercially in operation since June 22, 2012.

[Execution pages follow]

IN WITNESS WHEREOF the parties hereto have executed this Second Supplementary Agreement as of the date first above written.

NISICHAWAYASIHK CREE NATION

Per: ____________________

Per: ____________________

Per: ____________________

Per: ____________________

Per: ____________________

Per: ____________________

Per: ____________________

THE MANITOBA HYDRO-ELECTRIC BOARD

Per: ____________________

Per: ____________________

TASKINIGAHP POWER CORPORATION

Per: Ron Spence

Per: Shirley Linklater

5022649 MANITOBA LTD.

Per: Lorne M. Ford

Per: ____________________________

WUSKWATIM POWER LIMITED PARTNERSHIP

Per: Lorne M. Ford

Per: ____________________________

SCHEDULE 4.1
AMENDED AND RESTATED POWER PURCHASE AGREEMENT

AMENDED AND RESTATED POWER PURCHASE AGREEMENT

between

WUSKWATIM POWER LIMITED PARTNERSHIP

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD

DATED as of APRIL 1, 2014

TABLE OF CONTENTS

AMENDED AND RESTATED POWER PURCHASE AGREEMENT

DATED as of the first day of April, 2014

B E T W E E N:

WUSKWATIM POWER LIMITED PARTNERSHIP,

(hereinafter referred to as the "Limited Partnership")

- and –

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter referred to as "Hydro")

WHEREAS pursuant to the Construction Agreement dated June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as project manager, Hydro either directly or indirectly through subcontractors planned, designed, engineered, constructed and commissioned the Wuskwatim Project;

AND WHEREAS the Wuskwatim Project is being operated in conjunction with the Integrated Power System;

AND WHEREAS pursuant to the Interconnection and Operating Agreement entered into between Hydro (Transmission and Distribution Business Unit) and Hydro (Power Supply Business Unit) dated May 4, 2005 and subsequently assigned by Hydro (Power Supply Business Unit) to the Limited Partnership, the Wuskwatim Project will be interconnected to the Integrated Power System;

AND WHEREAS pursuant to the Operations and Maintenance Agreement dated June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as contractor, Hydro is managing and will continue to manage the operations and maintenance of the Wuskwatim Project;

AND WHEREAS pursuant to the System Operations and Dispatch Agreement dated June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, the Limited Partnership granted to Hydro the right and authority to control and operate the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station;

AND WHEREAS pursuant to the Power Purchase Agreement dated June 28, 2006 the Limited Partnership agreed to sell exclusively to Hydro and Hydro agreed to purchase all of the Net Actual Generation and capacity of the Wuskwatim Generating Station;

AND WHEREAS the parties have agreed to amend and restate the Power Purchase Agreement;.

NOW THEREFORE the Parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement and the preamble hereto, defined terms shall have the following meanings:

"**Additional Costs**" shall have the meaning specified in Section 3.1(h);

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person;

"**Adjustments**" shall have the meaning specified in Section 2.4;

"**Agreement**" means this amended and restated Power Purchase Agreement and the schedules attached hereto and instruments in amendment or confirmation of it; "**hereof**", "**hereto**" and "**hereunder**" and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; "**Article**", "**Section**" or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement;

"**Applicable Domestic Transactions**" means those Domestic Transactions or portions thereof for energy sold during the Applicable Domestic Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice;

"**Applicable Domestic Transaction Time Period**" means the twelve (12) month time period comprised of the month for which the applicable Domestic Transaction Rate is being determined plus the prior eleven (11) months;

"**Applicable Export Factor Time Period**" means the twelve (12) month time period comprised of the month for which the Export Factor is being determined plus the prior eleven (11) months plus the prior eleven (11) months;

"**Applicable Long-Term Transactions**" means the Long-Term Transactions or portion thereof for energy sold during the Applicable Long-Term Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice;

"**Applicable Long-Term Transaction Time Period**" means the twelve (12) month time period comprised of the month for which the applicable Long-Term Transaction Rate is being determined plus the prior eleven (11) months;;

"**Applicable On-Peak Opportunity Transactions**" shall have the meaning specified in Section 5.2;

"**Applicable Opportunity Transaction Time Period**" means the twelve (12) month time period comprised of the month for which the applicable Opportunity Transaction Rate is being determined plus the prior eleven (11);

"**Applicable Opportunity Transactions**" means those Opportunity Transactions or portions thereof for energy sold during the Applicable Opportunity Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice; "**Applicable Reliability Organization**" means any reliability standards organization whose standards Hydro has contracted to adhere to or having authority in the region in which the Wuskwatim Project is located;

"**Applicable Transaction Rate**" means the rate equal to the actual weighted average price over a twelve (12) month period, Hydro, as purchaser or as seller, is obligated to pay or is to be paid for the energy and capacity purchased or sold by Hydro;

"**Applicant**" shall have the meaning specified in Section 11.4;

"**Arbitrator**" means an arbitrator appointed in accordance with the procedures set out in Article XI of this Agreement;

"**Business**" means, the business carried on by the Limited Partnership consisting of the development, ownership, operation and maintenance of the Wuskwatim Project and any activities incidental or related thereto;

"**Business Day**" means any day on which Hydro's head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba;

"**Canadian Dollars**" and "**$**" each mean lawful money of Canada;

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interests in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights (other than debts securities convertible into an equity interest), warrants or options to subscribe for or acquire an equity interest in such Person;

"**Construction Agreement**" means the agreement dated June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as project manager, whereby Hydro, either directly or indirectly through subcontractors, designed, engineered, constructed and commissioned the Wuskwatim Project;

"**Control**" for the purposes of this Agreement, a Person (the "**first Person**") shall be deemed to be Controlled by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

(a) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

(b) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person, and "**Controlled**" **and** "**Controlling**" shall have the corresponding meaning;

"**Dispute**" shall have the meaning specified in Section 11.4;

"**Dispute Notice**" shall have the meaning specified in Section 11.4;

"Domestic Factor" shall have the meaning specified in Section 2.11;

"**Domestic Transactions**" means all written agreements or undertakings between Hydro and a Person located in Manitoba, other than an Affiliate of Hydro for the sale of energy and capacity;

"Domestic Transaction Rate" shall have the meaning specified in Section 2.13;

"**Energy Calculation**" means the compensation determined to be payable by Hydro to the Limited Partnership for Net Actual Generation under Article 2 or following an Energy Rate Review;

"**Energy Rate**" means the rate per MWh, Hydro will pay to the Limited Partnership in accordance with Sections 2.6, 2.7, 2.8 and 2.9 for the On-Peak Energy and the Off-Peak Energy respectively received by Hydro at the Point of Interconnection;

"**Energy Rate Review**" means a review conducted in accordance with Article XVII of the PDA of the pricing mechanisms used under this Agreement to determine the Energy Calculations;.

"**Equivalent Canadian Dollar Amount**" means, on any day with respect to any amount of U.S. Dollars, the equivalent amount of Canadian Dollars determined by using the Bank of Canada noon spot rate quoted by the CDCFUSD index in Bloomberg to provide Canadian Dollars in exchange for U.S. Dollars at approximately 12 noon (Toronto time) on such day;

"**Equivalent U.S. Dollar Amount**" means, on any day with respect to any amount of Canadian Dollars, the equivalent amount of U.S. Dollars determined by using the Bank of Canada noon spot rate quoted by the CDCFUSD index in Bloomberg to provide U.S. Dollars in exchange for Canadian Dollars at approximately 12 noon (Toronto time) on such day;

"**Event of Hydro Default**" shall have the meaning specified in Section 10.3.

"**Event of Limited Partnership Default**" shall have the meaning specified in Section 9.1.

"Excess Spill Energy Review" means the review of the methodology, assumptions and pricing principles for the determination of Excess Spill Energy Revenue Adjustment pursuant to Section 9.4;

"**Expert**" means an expert appointed pursuant to the PDA to conduct an Energy Rate Review or a Transaction Rate Review;

"Export Factor" shall have the meaning specified in Section 2.10;

"**GAAP**" means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the Chartered Professional Accountants of Canada, or any successor Person at such time;

"**General Partner**" means 5022649 Manitoba Ltd. in its capacity as general partner of the Limited Partnership pursuant to the terms of the Limited Partnership Agreement;

"**Generator Units**" means the three units, each consisting of a vertical-shaft, fixed blade propeller-type turbine and vertical umbrella-type generator installed as part of the Wuskwatim Project pursuant to the Construction Agreement and "**Generator Unit**" means any of the Generator Units;

"**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region;

"**Governmental Authority**" means any federal, provincial, local or other governmental, regulatory or administrative agency, court, commission, department, board or other governmental subdivision, legislature, rulemaking board, tribunal, or arbitration body having jurisdiction over either Party;

"**GWh**" means gigawatt-hours;

"**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the *Hydro Act*;

"**Hydro Act"** means *The Manitoba Hydro Act*,C.C.S.M. , c. H190, as amended from time to time;

"**Hydro Contractual Obligation**" means any provision of any agreement, instrument or written undertaking to which Hydro is a party or by which it or any of its Property is bound, which materially impacts on the Integrated Power System and was entered into without regard to the ownership of the Wuskwatim Project and the existence of this Agreement;

"**Hydro Financial Year**" means, the financial year of Hydro, currently commencing on April 1 of each calendar year and ending on March 31 of the next calendar year;

"**Hydro High Voltage Transmission System**" means that portion of the Hydro Transmission System designated by Hydro, as such, from time to time;

"**Hydro High Voltage Transmission System Energy Losses**" shall have the meaning specified in Section 4.2;

"**Hydro Metering Equipment**" shall have the meaning specified in Section 4.3;

"**Hydro Transmission System**" means the transmission facilities owned and operated or operated by Hydro which are a component of the Integrated Power System;

"**Initial Closing Date**" shall have the meaning ascribed thereto in the PDA;

"**Initial Limited Partnership Agreement**" means the limited partnership agreement entered into between the General Partner, and Hydro in its capacity as limited partner, dated the 9th day of December, 2004;

"**Initial PPA**" means the Power Purchase Agreement dated June 28, 2006 between Hydro and the Limited Partnership;

"**In-Service" or "In-Service Date**" means the date on which a particular Generator Unit was fully commissioned and came into service as evidenced by a commissioning certificate issued for the unit by Hydro's commissioning engineer;

"**Insufficient Long-Term Transaction Year**" shall have the meaning ascribed thereto in Section 5.2;

"**Insufficient Transactions"** means for the relevant rate calculation either less than a total of 800 GWh of energy bought or sold as Long-Term Transactions applicable at that time or less than a total of 1500 GWh of energy bought or sold as the Opportunity Transactions during the time;

"**Integrated Power System**" means the system of hydraulic and thermal electric generation and power transmission facilities owned and operated or operated by Hydro, which system is interconnected with other power utilities;

"**Interconnection and Operating Agreement**" means the Interconnection and Operating Agreement entered into between Hydro (Transmission and Distribution Business Unit) and Hydro (Power Supply Business Unit) dated May 4, 2005, as amended or replaced from time to time and subsequently assigned by Hydro (Power Supply Business Unit) to the Limited Partnership, whereby the Wuskwatim Project will be interconnected to the Integrated Power System;

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws;

"**Licences**" means all authorizations, approvals, consents, registrations and certificates required by any Governmental Authority for the construction, operation or maintenance of the Wuskwatim Project;

"**Limited Partner**" means one or both of Hydro and Taskinigahp Power Corporation as the context requires, in their capacity as limited partners of the Limited Partnership; "**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement as amended and restated by the second and third Limited Partnership Agreements, for the purposes of owning and directly or indirectly planning, designing, constructing, operating and maintaining the Wuskwatim Project

"**Limited Partnership Agreement**" means the third amended and restated limited partnership agreement amending and restating the second amended and restated limited partnership agreement dated June 28, 2006 and the Initial Limited Partnership Agreement, dated the same day as this Agreement between the General Partner in its capacity as General Partner and Hydro and Taskinigahp Power Corporation as limited partners;

"**Limited Partnership Contractual Obligation**" means any provision of any agreement, instrument or undertaking to which the Limited Partnership is a party or by which it or any of its Property is bound;

"**Long-Term Transaction Rate**" shall have the meaning specified in Section 2.12;

"**Long-Term Transactions**" means all written agreements or undertakings between Hydro and a Person, other than an Affiliate of Hydro, for the purchase or sale of energy physically crossing a Manitoba border and the cross-border capacity, which meets the following criteria:

(a) Hydro is pursuant to the written agreement or undertaking exporting or importing energy to or from electricity markets outside of Manitoba;

(b) the written agreement or undertaking was entered into on or after the Initial Closing Date;

(c) the seller under the written agreement or undertaking has included the commitments made under the written agreement or undertaking, as a factor in the operation, planning and development of its energy system, in order to maintain sufficient resources to meet those commitments, and either:

(i) the time period between the date the written agreement or undertaking is entered into and the date energy is first supplied pursuant to the written agreement or undertaking is at least 365 days in duration; or

(ii) if the time period is less than 365 days, but the written agreement or undertaking has a component whereby energy will be supplied 365 days after the date the written agreement or undertaking is entered into, that component of the written agreement, or undertaking shall be included as part of the Long-Term Transactions;

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in and of itself, but which cumulatively results in a material adverse effect) that precludes or materially restricts the ability of the Limited Partnership from performing any of its obligations under this Agreement;

"**MWh**" means megawatt-hours

"NCN Total Outstandings" means the Total Outstandings of NCN (as that term is defined in the Second NCN Financing Agreement), plus all accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility (as that term is defined in the Second NCN Financing Agreement)**;**

"**Net Actual Generation**" means the actual energy generated by the Wuskwatim Project during the applicable period less any energy generated which is used for the Wuskwatim Project's station service or auxiliaries but includes only the energy generated from each Generator Unit after its In-Service Date;

"**Notice**" means any written notice, citation, directive, request for information, writ, summons and statement of claim or other communication from any Person other than the Parties;

"**Off-Peak Energy**" means that portion of the Net Actual Generation delivered by the Wuskwatim Project to the Point of Interconnection during Off-Peak Hours;

"**Off-Peak Energy to Date**" means the Off-Peak Energy received by Hydro during the period of time from the first day of the applicable Hydro Financial Year to the last day of the applicable month in that Hydro Financial Year for which the Off-Peak Energy Payment is to be calculated in accordance with sections 2.8 and 2.9 of this Agreement;

"**Off-Peak Hours**" means the period of time which is not included in the On-Peak Hours;

"**Off-Peak Opportunity Transactions**" means those Opportunity Transactions where the sale or purchase of energy and capacity is in respect of energy sold or received only during Off-Peak Hours but if an Opportunity Transaction includes energy sold or received during Off-Peak Hours and On-Peak Hours, only those Opportunity Transactions sold or received during Off-Peak Hours shall be considered Off-Peak Opportunity Transactions;

"**On-Peak Energy**" means that portion of the Net Actual Generation delivered by the Wuskwatim Project to the Point of Interconnection during On-Peak Hours;

"On-Peak Energy to Date" means the On-Peak Energy received by Hydro during the period of time from the first day of the applicable Hydro Financial Year to the last day of the applicable month in that Hydro Financial Year for which the On-Peak Energy Payment is to be calculated in accordance with section 2.6 and 2.7 of this Agreement;

"**On-Peak Hours**" means the period of time between 6:00 a.m. and 10:00 p.m. central standard time, Monday through Friday excluding holidays designated by the North American Electric Reliability Council or any successor agency;

"**On-Peak Opportunity Transaction Rate**" shall have the meaning specified in Section 5.2;

"**On-Peak Opportunity Transactions**" means those Opportunity Transactions where the sale or purchase of energy is for energy sold or received only during the On-Peak Hours but if an Opportunity Transaction includes energy sold or received during Off-Peak Hours and On-Peak Hours, only those Opportunity Transactions sold or received during the On-Peak Hoursshall be considered On-Peak Transactions;

"**Operations and Maintenance Agreement**" means an agreement dated June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project and Hydro, whereby Hydro will manage the operations and maintenance of the Wuskwatim Project, as amended or replaced from time to time;

"**Opportunity Transaction Rate**" shall have the meaning specified in Section 2.14;

"**Opportunity Transactions**" means all agreements or undertakings between Hydro and a Person, other than an Affiliate of Hydro, for the sale or purchase of energy physically crossing a Manitoba border and cross-border capacity which meets the following criteria:

(a) the agreement or undertaking was entered into on or after the Initial Closing Date;

(b) the agreement or undertaking is not a Long-Term Transaction; and

(c) Hydro is pursuant to the agreement or undertaking exporting or importing energy to or from electricity markets outside of Manitoba;

"**PDA**" means for purposes of this Agreement, the Wuskwatim Project Development Agreement dated June 28, 2006 amended by the PDA Supplement No. 1 dated March 15, 2011 and PDA Supplement No. 2 dated as of March 31, 2015;

"**Party**" means either the Limited Partnership or Hydro and "**Parties**" means both the Limited Partnership and Hydro;

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture or other entity or Governmental Authority, and pronouns have a similarly extended meaning;

"**Point of Interconnection**" shall mean the point on the output (high) side of the step up transformer located on the tail race deck of the Wuskwatim Generating Station at which each of the Generator Units connects to one of the three 230 kV transmission lines running from the Wuskwatim Generating Station to the switching station;

"**Pricing Criteria**" shall have the meaning specified in Section 6.3;

"**Pricing Principle**" shall have the meaning specified in Section 6.2;

"**Property**" means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including Capital Stock in any other Person;

"**Rate Review**" means an Energy Rate Review, an Excess Spill Energy Review or a Transaction Rate Review, as the case may be and "**Rate Reviews**" means all of them;

"**Reply**" shall have the meaning specified in Section 11.5;

"**Respondent**" shall have the meaning specified in Section 11.5;

"**Second NCN Financing Agreement"** means the amended and restated NCN Financing Agreement dated April 16, 2015;

"Second TPC Financing Agreement" means the amended and restated TPC Financing Agreement dated April 16, 2015;

"**System Operations and Dispatch Agreement**" means an agreement dated even date herewith, between the Limited Partnership and Hydro whereby Hydro will control and operate the Wuskwatim Project on behalf of the Limited Partnership, including matters related to the dispatch of the Wuskwatim Generating Station as amended or replaced from time to time;

"TPC Total Outstandings" means the Total Outstandings of TPC (as that term is defined in the Second TPC Financing Agreement), plus all accrued and unpaid interest and all other amounts owing by NCN under the Equity Credit Facility (as that term is defined in the Second TPC Financing Agreement);

"**Term**" means the initial and subsequent term of this Agreement as specified in Section 2.19;

"**Transaction Rate Review**" means a review conducted in accordance with Article XVII of the PDA of the determination, allocation and Adjustments made by Hydro pursuant to Article 2 of this Agreement in the calculation of the Long Term Transaction Rate, the Domestic Transaction Rate and the Opportunity Transaction Rate;

"**Transmission Owner Interconnection Facilities**" shall have the meaning ascribed thereto in the Interconnection and Operating Agreement;

"**U.S. Dollars** means lawful money of the United States of America;

"**Wuskwatim Generating Station**" shall have the meaning ascribed thereto in the PDA; and

"**Wuskwatim Project**" shall have the meaning ascribed thereto in the PDA.

1.2 Interpretation.

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, or any provisions hereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(e) the expressions "the aggregate", "the total", "the sum" and expressions of similar meaning shall mean "the aggregate (or total or sum) without duplication";

(f) in the computation of periods of time, unless otherwise expressly provided, the word "from" means "from and including" and the words "to" and "until" mean "to but excluding"; and

(g) accounting terms not specifically defined shall be construed in accordance with GAAP.

1.3 Severability.

If any provision of this Agreement is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions of this Agreement shall continue to be valid and enforceable.

1.4 Entire Agreement.

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, of the Parties, whether oral or written, prior to the date of this Agreement.

1.5 Waiver.

No failure on the part of a Party to exercise, and no delay in exercising, any right under this Agreement shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement preclude any other or further exercise thereof or the exercise of any other right; nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No Notice to or demand on the Limited Partnership in any case shall entitle it to any Notice or demand in similar or other circumstances. No waiver of any of the provisions of this Agreement shall be effective unless it is in writing duly executed by the waiving Party.

1.6 No Presumption.

The Parties have endeavoured to ensure that the terms of this Agreement are as clear and unambiguous so unless expressly provided there shall be no presumption in favour of or against any Party.

1.7 Governing Law.

This Agreement shall be governed by, and interpreted in accordance with, the applicable Laws of Manitoba and Canada.

1.8 Incorporation of Schedules.

The following schedules shall be incorporated into and form an integral part of this Agreement:

Schedule A	-	Arbitrator's Undertaking
Schedule B	-	Notices

1.9 Acknowledgement.

The Parties acknowledge that:

(a) the Limited Partnership is a limited partnership formed under the Laws of Manitoba, and each limited partner is only liable for its respective liabilities or losses to the extent of the amount that the limited partner has contributed or agreed to contribute to the capital of the limited partnership and the limited partner's pro rata share of any undistributed income;

(b) the obligations of the Limited Partnership shall not be personally binding upon, nor shall resort be had to, the property of any of the limited partners, their successors and assigns, and that resort shall only be had to the property of the Limited Partnership or the property of its General Partner;

(c) the General Partner is the sole general partner of the Limited Partnership; and

(d) nothing in this Agreement shall be deemed to detract from or limit or restrict in any way the limited liability of any Limited Partner.

ARTICLE II
SALE AND PURCHASE OF ENERGY

2.1 <u>Net Actual Generation and Charge.</u>

Subject to the terms and conditions of this Agreement, the Limited Partnership agrees to sell and Hydro agrees to purchase the Net Actual Generation and capacity of the Wuskwatim Project and the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection determined in accordance with Sections 2.2 and 2.3 and capacity in accordance with Section 2.4.

2.2 <u>Energy Calculations – Financial Years 2014/15 to 2023/24.</u>

Subject to the terms and conditions of this Agreement including any Adjustments, Rate Reviews and the set-off of any amounts the Limited Partnership is obligated to pay Hydro pursuant to the provisions of Section 3.1(j), for the Hydro Financial Years 2014/15 to 2023/24 the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection, on a Canadian Dollar per MWh basis, determined by calculating the On-Peak Energy in accordance with Section 2.6, the Off-Peak Energy in accordance with Section 2.8, the On-Peak Energy to Date, the Off-Peak Energy to Date, the Export Factor in accordance with Section 2.10, the Domestic Factor in accordance with Section 2.11, the Long Term Transaction Rate in accordance with Section 2.12, the Domestic Transaction Rate in accordance with Section 2.13, the Opportunity Transaction Rate in accordance with Section 2.14 and the Spill Energy Revenue Adjustment in accordance with Article IX.

2.3 Energy Calculations – Financial Years 2024/25 and Onward.

Subject to the terms and conditions of this Agreement including any Adjustments, Rate Reviews and the set-off of all amounts the Limited Partnership is obligated to pay Hydro pursuant to the provisions of Section 3.1(j), for the Hydro Financial Years commencing April 1, 2024 and each Hydro Financial Year thereafter the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection, on a Canadian Dollar per MWh basis, determined by calculating the On-Peak Energy in accordance with Section 2.7, the Off-Peak Energy in accordance with Section 2.9, the On-Peak Energy to Date, the Off-Peak Energy to Date, the Export Factor in accordance with Section 2.10, the Long Term Transaction Rate in accordance with Section 2.12, the Opportunity Transaction Rate in accordance with Section 2.14, and the Spill Energy Revenue Adjustment in accordance with Article IX.

2.4 Allocations and Adjustments.

When making the Energy Calculations in Sections 2.2 and 2.3 Hydro, acting reasonably shall make the allocations and adjustments permitted by this Agreement, including in the case of energy exported and sold across Manitoba borders, (i) the portion of the price, if any, payable for capacity attributable to the portion of the energy that physically crossed a Manitoba border; and (ii) the actual costs or expenses incurred which were reasonably necessary to provide access to export markets or facilitate Hydro entering into export markets, but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses for which Hydro has been reimbursed pursuant to other provisions of this Agreement ("the **Adjustments**");

2.5 Hydro to Provide Monthly Information to the Limited Partnership.

Hydro shall, within ten (10) Business Days of the last day of each month during each Hydro Financial Year except in the last month, in which case, within fifteen (15) Business Days, provide the Limited Partnership with written notice of:

(a) the Domestic Transaction Rate;

(b) the Long Term Transaction Rate;

(c)the Opportunity Transaction Rate; and

(d) the amounts paid for On-Peak Energy and Off-Peak Energy for the month less any Adjustments or set-off pursuant to Section 3.1(j);

2.6 <u>On-Peak Energy Payment - Financial Years 2014/15 to 2023/24.</u>

For each month in a Hydro Financial Year from April 1, 2014 to March 31, 2024, Hydro shall pay to the Limited Partnership for On-Peak Energy an amount equal to the product of the monthly Long Term Transaction Rate, the On Peak Energy to Date, and the Export Factor plus the product of the Domestic Transaction Rate, the On-Peak Energy to Date and the Domestic Factor, minus the sum of the amounts paid or payable by Hydro for On-Peak Energy to the end of the prior month ("**On-Peak Energy Payments to Date**"). The calculation of the amount payable for On-Peak Energy under this Section 2.6 may be expressed by the following formula:

(A x B x C) + (D x B x E) – On-Peak Energy Payments to Date

Where:

A = Long Term Transaction Rate

B = On Peak Energy to Date

C = Export Factor

D = Domestic Transaction Rate

E = Domestic Factor

2.7 <u>On- Peak Energy Payments - Financial Years 2024/25 and Onward.</u>

For each month in the Hydro Financial Year commencing April 1, 2024 and thereafter Hydro shall pay to the Limited Partnership for On-Peak Energy an amount equal to the product of the monthly Long Term Transaction Rate, the On Peak Energy to Date, and the Export Factor minus the On-Peak Energy Payments to Date. The calculation of the amount payable for On-Peak Energy under this Section 2.7 may be expressed by the following formula:

(A x B x C) – On-Peak Energy Payments to Date

Where:

A = Long Term Transaction Rate

B = On Peak Energy to Date

C = Export Factor

2.8 Off-Peak Energy Payments - Financial Years 2014/15 to 2023/24.

For each month in a Hydro Financial Year from April 1, 2014 to March 31, 2014, Hydro shall pay to the Limited Partnership for Off-Peak Energy an amount equal to the product of the Opportunity Transaction Rate, the Export Factor and the Off Peak Energy To Date, plus the product of the Domestic Transaction Rate, the Off-Peak Energy to Date and the Domestic Factor, minus the sum of the amounts paid or payable by Hydro for Off-Peak Energy to the end of the prior month ("**Off-Peak Energy Payments to Date**"). The calculation of the amount payable for Off-Peak Energy under this Section 2.8 may be expressed by the following formula:

(F x G x C) + (D x G x E) – Off-Peak Energy Payments to Date

Where:

C = Export Factor

D = Domestic Transaction Rate

E = Domestic Factor

F = Opportunity Transaction Rate

G = Off-Peak Energy to Date

2.9 Off-Peak Energy Payment Financial Years 2024/25 and Onward.

For each month in the Hydro Financial Years commencing April 1, 2024 and thereafter, Hydro shall pay to the Limited Partnership for Off-Peak Energy an amount equal to the product of the Opportunity Transaction Rate, the Export Factor and the Off-Peak Energy To Date minus the Off-Peak Energy Payments to Date. The calculation of the amount payable for Off-Peak Energy under this Section 2.9 may be expressed by the following formula:

(F x G x C) – Off-Peak Energy Payments to Date

Where:

C = Export Factor

F = Opportunity Transaction Rate

G = Off-Peak Energy to Date

2.10 Export Factor.

The "**Export Factor**" means a factor that is equal to the weighted average proportion of Net Energy Delivered by the Integrated Power System over a twelve (12) month period that is exported by Hydro, during that twelve (12) month period. The monthly Export Factor shall be calculated for each month during the Hydro Financial Year using the following formula:

A / (A + B) where,

A is equal to the total energy generated by Hydro related to the export sales that physically crossed a Manitoba border; and

B is equal to the total energy generated by Hydro delivered in Manitoba

For any period from and after April 1, 2024 the monthly Export Factor shall be one (1.00).

2.11 Domestic Factor.

The Domestic Factor means a factor equal to one (1.00) minus the monthly Export Factor for each month during the Hydro Financial Year.

2.12 Long-Term Transaction Rate.

The "**Long-Term Transaction Rate**" means the Applicable Transaction Rate for Long-Term Transactions determined for each month during a Hydro Financial Year for the applicable Long Term Transaction Time Period determined in the following manner:

(a) adjustments to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Long-Term Transactions;

(b) the price paid or payable for Applicable Long-Term Transactions determined in Canadian Dollars per MWh, and if the payments are in U.S. Dollars for any of the Applicable Long Term Transactions the amounts shall be converted to Canadian Dollars pursuant to Section 2.15 after the adjustments referred to in Section 2.12 (b) using the average Equivalent Canadian Dollar Amount for the month during which the entitlement to be paid arises; and

(c) the Long-Term Transaction Rate expressed in Canadian Dollars per MWh calculated by dividing the total net amount that Hydro is entitled to be paid or is obligated to pay for the Applicable Long-Term Transactions by the total energy imported or exported as Applicable Long-Term Transactions.

2.13 Domestic Transaction Rate.

The "**Domestic Transaction Rate**" means the Applicable Transaction Rate for Domestic Transactions determined for each month during a Hydro Financial Year for the Applicable Domestic Transactions expressed in Canadian Dollars per MWh and calculated by dividing the total net amount Hydro is entitled to be paid or is obligated to pay for the Applicable Domestic Transactions by the total energy delivered as Applicable Domestic Transactions.

2.14 Opportunity Transaction Rate.

The "**Opportunity Transaction Rate**" means the Applicable Transaction Rate for Opportunity Transactions determined for each month during a Hydro Financial Year for the applicable Opportunity Transaction Time Period determined in the following manner:

(a) adjustments to reflect the price at a Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Opportunity Transactions;

(b) the price paid or payable for Applicable Opportunity Transactions determined in Canadian Dollars per MWh, and if the payments are in U.S. Dollars for any of the Applicable Opportunity Transactions the amounts shall be converted to Canadian Dollars in accordance with Section 2.15 after the adjustments referred to in Section 2.16 (b) using the average Equivalent Canadian Dollar Amount for the month during which the entitlement to payment arises; and

(c) the Opportunity Transaction Rate expressed in Canadian Dollars per MWh and calculated by dividing the total net amount Hydro is entitled to be paid or obligated to pay for the Applicable Opportunity Transactions by the total energy delivered as Applicable Opportunity Transactions.

2.15 U.S. Dollar Conversion Option.

The Limited Partnership can if it has provided written notice to Hydro on or before the last Business Day of any particular month require that a percentage not exceeding fifty percent (50%) of the amount that would otherwise be billed to Hydro in Canadian Dollars, for the Net Actual Generation received by Hydro during that month, be converted to U.S. Dollars, by reference to the Equivalent U.S. Dollar Amount as of the last Business Day of that month and that amount shall be paid to the Limited Partnership, in U.S. Dollars, by the dates specified in accordance with Section 8.1(3).

2.16 Acknowledgement of Limited Partnership.

The Limited Partnership expressly acknowledges and agrees that:

(a) the compensation to be paid under this Agreement entitles Hydro to receive all the capacity and the energy from the Wuskwatim Project;

(b) the rates and compensation to be paid in this Agreement, subject to Section 2.20 is based on the Net Actual Generation actually received by Hydro at the Point of Interconnection; and

(c) the Limited Partnership is not entitled to an additional payment or separate rate for the capacity of the Wuskwatim Project which Hydro is entitled to receive pursuant to this Agreement.

2.18 Insufficiency of Capacity, Disruption or Failure of the Hydro Transmission System.

Notwithstanding any other provision of this Agreement, if the Net Actual Generation cannot be generated and delivered to the Point of Interconnection primarily due to insufficient capacity of the Hydro Transmission System or the disruption to or failure of the Hydro Transmission System and as a direct consequence thereof, water is spilled at the Wuskwatim Project spillway, Hydro shall be deemed for the purposes of this Agreement to have received the energy that could have been generated from the water that was spilled at the Wuskwatim Project spillway during that time period less the applicable Hydro High Voltage Transmission System Energy Losses. This Section 2.18 shall not apply and Hydro shall not be deemed for the purposes of this Agreement or otherwise to have received energy that was not generated and delivered to the Point of Interconnection if the insufficient capacity of the Hydro Transmission System, disruption to or failure of the Hydro Transmission System occurred as a result of or was primarily due to: (i) a breach by the Limited Partnership of any provision of the Limited Partnership's Contractual Obligation; or (ii) any act or omission reasonably associated with the provisions of the Construction Agreement, the System Operations and Dispatch Agreement or the Operations and Maintenance Agreement, including without limiting the generality of the foregoing in respect of services or work performed or to be performed by Hydro under the provisions of those Agreements or the breach by Hydro of any provision of those Agreements. If this Section 2.18 is applicable, Hydro shall provide to the Limited Partnership a calculation of the amount of energy that could have been generated and delivered during the applicable time period from the water that was spilled using the best information and data available and Hydro shall be required to pay to the Limited Partnership the amount that would otherwise be determined to be owing pursuant to the provisions of this Agreement (after all set-offs, deductions and adjustments provided for in this Agreement including adjustment for the Hydro High Voltage Transmission System Energy Losses applicable for the period of time during which water was spilled) if that amount of energy had been generated and delivered to the Hydro Transmission System during that period of time from the water that was spilled. The Limited Partnership expressly acknowledges that the risk of the Limited Partnership not being able to generate and deliver energy to the Point of

Interconnection from all other matters or circumstances is borne solely by the Limited Partnership.

2.19 Term.

(a) The Term of this Agreement shall be from April 1, 2013 to March 31, 2038 unless extended or terminated pursuant to the provisions of this Agreement. The Term shall automatically be extended for periods of twenty-five (25) years each starting on April 1, 2038 subject to the following conditions being in effect for the period of time for which the Term is to be extended:

(i) Hydro or an Affiliate of Hydro must have an agreement with the Limited Partnership to operate and dispatch the Wuskwatim Project on substantially the same terms and conditions as those contained in the System Operations and Dispatch Agreement, or the Term shall be extended, subject to such amendments to the terms and conditions of this Agreement as Hydro acting reasonably may require if Hydro or an Affiliate of Hydro is not operating and controlling the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station on substantially the same terms and conditions as those contained in the System Operations and Dispatch Agreement or if any other Person is operating and controlling the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station; and

(ii) Hydro or an Affiliate of Hydro must have an agreement with the Limited Partnership to maintain and operate the Wuskwatim Project on substantially the same terms and conditions as those contained in the Operations and Maintenance Agreement, or the Term shall be extended, subject to such amendments to the terms and conditions of this Agreement as Hydro acting reasonably may require if Hydro or an Affiliate of Hydro is not operating and maintaining on substantially the same terms and conditions in the Operations and Maintenance Agreement or if any other Person is maintaining and operating the Wuskwatim Project.

(b)Upon expiry of a Term or upon the termination of this Agreement, Hydro shall have no future or further obligation to purchase the Net Actual Generation and capacity of the Wuskwatim Generating Station or to make any further payments to the Limited Partnership and except for Hydro's and the Limited Partnership's rights and obligations arising prior to the expiry of the

Term, the rights and obligations of the Parties under this Agreement shall end and the Limited Partnership shall be entitled to sell the energy and capacity of the Wuskwatim Generating Station to another Person. This Agreement shall not be construed to provide a residual value to either the Limited Partnership or Hydro or to any Person, for the right to use or benefit from the Limited Partnership's or Hydro's Property or the Integrated Power System following the expiry of the Term.

ARTICLE III
AFFIRMATIVE COVENANTS

3.1 Covenants.

During the Term of this Agreement the Limited Partnership agrees to be bound by and to perform each of the following affirmative obligations:

(a) **Licences**. The Limited Partnership shall seek, obtain, maintain, comply with and as necessary, review and modify from time to time, at the Limited Partnership's sole expense, the Licences.

(b) **Maintenance and Operation of the Wuskwatim Project**. The Limited Partnership shall operate, maintain and repair at the Limited Partnership's sole expense, the Wuskwatim Project in accordance with the reasonable guidelines, procedures, decisions, practices and policies of Hydro (or any Affiliate of Hydro) as amended from time to time and communicated by Hydro to the Limited Partnership and in accordance with the provisions of the Limited Partnership Contractual Obligations.

(c) **Applicable Reliability Organization and Governmental Authority**. The Limited Partnership shall at the Limited Partnership's sole expense:

(i) cooperate to a reasonable extent with Hydro in fulfilling Hydro's duties and obligations (or the duties and obligations of any Affiliate of Hydro) as a participant in the Applicable Reliability Organization and pursuant to the Hydro Contractual Obligations, as amended from time to time in the same manner and to the same extent as Hydro (or any Affiliate of Hydro), as Hydro may advise;

(ii) cooperate with and provide in a timely manner any and all information or data required by the Applicable Reliability Organization or by Hydro for the Applicable Reliability Organization and any other necessary approvals related to the Wuskwatim Project, as Hydro may advise;

(iii) comply with the Applicable Reliability Organization procedures, decisions and policies, as Hydro may advise;

(iv) be bound by those requirements, decisions and policies of the Applicable Reliability Organization, as Hydro may advise, and those Hydro Contractual Obligations as amended from time to time, in the same manner and to the same extent as Hydro (or any Affiliate of Hydro), as Hydro may advise; and

(v) reimburse Hydro for actual costs and expenses imposed on Hydro (or any Affiliate of Hydro) by the Applicable Reliability Organization or Government Authority or pursuant to the Hydro Contractual Obligations which are associated with this Agreement or the Wuskwatim Project and any filing fees incurred by Hydro as a result of the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement.

(d) **Point of Interconnection**. The Limited Partnership shall at the Limited Partnership's sole expense:

(i) cooperate with Hydro in maintaining the interconnection of the Wuskwatim Project to the Integrated Power System, and comply with all provisions of the Interconnection and Operating Agreement;

(ii) subject to Articles 2.10 to 2.13 of the PDA, modify the design of the Wuskwatim Project at any time in a manner consistent with Hydro's direction to ensure the interconnection and synchronous operation of the Wuskwatim Project with the Integrated Power System will be safe and reliable and will not adversely affect the Integrated Power System or any other utility's system, or services provided to Hydro's customers; and

(iii) cause the Net Actual Generation to be delivered to Hydro at the Point of Interconnection.

(e) **Fines and Penalties**. If fees, levies, fines, penalties, or costs or expenses are assessed against Hydro by any Governmental Authority due to non-compliance by the Limited Partnership of any provision of this Agreement or reasonably attributed to by the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement unless same relates to an Event of Hydro Default, the Limited Partnership shall indemnify and hold Hydro harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Hydro, including claims for indemnity or contribution made by third parties against Hydro.

(f) **Taxes and Fees**. Subject to Section 3.1(h) the Limited Partnership shall be responsible for and pay all present or future federal, provincial, municipal or other lawful taxes (for greater certainty this does not include any income taxes that may be payable by Hydro), duties, levies or fees, which without limiting the generality of the foregoing shall include any value added tax or similar taxes, imposed directly or indirectly, which are applicable to Hydro or the Limited Partnership or the Wuskwatim Project by reason of the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement without any reimbursement in whole or in part from Hydro or Hydro shall, if such amounts have been paid by it, be entitled to bill the Limited Partnership in accordance with Article VIII and receive payment.

(g) **Additional Costs**. If the application of any Laws (including any interpretation thereof) causes Hydro to be liable for additional taxes (for greater certainty this does not include any income taxes that may be payable by Hydro),, fees or assessments ("**Additional Costs**") reasonably attributable to the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement, Hydro may bill the Limited Partnership monthly for such Additional Costs pursuant to Article VIII and receive payment on account of these Additional Costs. These Additional Costs will be calculated so as to place Hydro in the same economic position (considering the timing of the Additional Costs and any expected benefits resulting from said taxes, fees, assessments by third parties) in which it would have been if it had not be liable for the Additional Costs.

(h) **Environmental Credits**. The Limited Partnership shall obtain in its own name any and all environmental credits necessary to operate the Wuskwatim Project in compliance with Laws. Hydro acknowledges that any environmental credits will be assets of or credited to the Limited Partnership as applicable, conditional on the value of such environmental credits having not already been included in the Energy Calculation.

(i) **Dispatch**. The Limited Partnership agrees that the Wuskwatim Generating Station shall at all times be operated and dispatched by Hydro in accordance with the guidelines, procedures, decisions, practices and policies of Hydro's (or any Affiliate of Hydro) as amended from time to time and Hydro's Contractual Obligations as amended from time to time and communicated by Hydro to the Limited Partnership and in accordance with the provisions of the System Operations and Dispatch Agreement, the Interconnection and Operating Agreement and the Operations and Maintenance Agreement.

(j) **Fee**. Commencing the month following the month in which both the NCN Total Outstandings and the TPC Total Outstandings have been repaid in full the Limited Partnership shall pay Hydro for each month a fee equal to thirty-six percent (36%) of the Energy Calculation payable by Hydro for that month in accordance with the provisions this Agreement plus all present or future Federal, Provincial, Municipal or other lawful taxes, (for greater certainty this does not include any income taxes that may be payable by Hydro) duties, levies or fees, which without limiting the generality of the foregoing should include any value added tax or similar taxes, imposed directly or indirectly on Hydro or the Limited Partnership in respect of the fee. This fee is to compensate Hydro for:

(i) assuming the risk that the energy purchased pursuant to this Agreement cannot be sold as a Long-Term Transaction;

(ii) not requiring the Limited Partnership pursuant to this Agreement to supply a minimum amount of On-Peak Energy;

(iii) costs of lost opportunities arising from the utilization of Hydro's transmission tie-line capacity as a consequence of Hydro's purchase of energy and capacity pursuant to this Agreement at the Point of Interconnection;

(iv) assuming the transmission risk in Manitoba associated with Hydro's acceptance of the delivery of all of the energy pursuant to this Agreement at the Point of Interconnection for resale at a different delivery point; and

(v) the suspension of marketing and certain other fees that would have otherwise been payable under the terms of the Initial PDA, had it remained in effect, implemented during the period loans are outstanding under the NCN Financing Agreement and the TPC Financing Agreement.

Hydro may bill this fee to the Limited Partnership or set it off against the amount otherwise due to the Limited Partnership pursuant to the provisions of this Agreement.

(k) **Records**. The Limited Partnership shall prepare and maintain or cause to be prepared and maintained complete and accurate operating and other records as Hydro may from time to time request, acting reasonably. This shall include all records required by any Applicable Reliability Organization to maintain accredited capacity for the Wuskwatim Generating Station. Without limiting the generality of the foregoing the Limited Partnership shall on written notice from Hydro provide or cause to be provided all documents and information necessary to meet the accreditation requirements for the Wuskwatim Generating Station of any Applicable Reliability Organization during the Term of this Agreement. The Limited Partnership acknowledges that Hydro may release such information and documentation to the Applicable Reliability Organization in respect of any application or maintenance of accredited capacity for the Wuskwatim Generating Station. In addition Hydro shall have access to inspect and test such metering and other recording equipment and operating records as may be required in respect of any accreditation process.

(l) **Inspection**. The Limited Partnership shall provide Hydro and its representatives with access to the Wuskwatim Project and the records relating to the Wuskwatim Project including all records required to be prepared and maintained in accordance with Section 3.1(k) of this Agreement and Hydro shall be entitled to make and retain copies of all such records. The inspection of the Wuskwatim Project and the review of the records shall not relieve the Limited Partnership of any of its obligations under this Agreement.

3.2 Acknowledgement and Waiver.

The Limited Partnership expressly acknowledges and agrees that the covenants in section 3.1 are obligations solely of the Limited Partnership and that while Hydro may be a party to other agreements with the Limited Partnership, in respect of certain matters related to the aforesaid covenants, the Limited Partnership shall be bound by and shall be responsible for the performance of the aforesaid covenants in accordance with the provisions of this Agreement and any breach of the aforesaid covenants shall be an Event of Limited Partnership Default in accordance with the provisions of this Agreement. The Limited Partnership waives any right to:

(a) defend a claim by Hydro that an Event of Limited Partnership Default has occurred under the provisions of this Agreement; or

(b) to claim Hydro contributed to the breach of any provision of this Agreement; or

(c) refuse to make any payment that is required to be made pursuant to the provisions of this Agreement or to not comply with any other provision of this Agreement;

due to or as a result of an act or omission in any way associated with the provisions of the Construction Agreement, the System Operations and Dispatch Agreement, the Operations and Maintenance Agreement or the Interconnection and Operating Agreement, and without restricting the generality of the foregoing would include any breach by Hydro of any provision of those agreements or the supply of services by Hydro or the performance of work by Hydro under the provision of those agreements. The waiver of rights by the Limited Partnership does not extend to any act or omission by Hydro under any of the aforesaid agreements, for which Hydro is found to be liable under those agreements due to Hydro's gross negligence or willful misconduct.

ARTICLE IV
METERING

4.1 **Determination of Energy Delivered.**

The amount of On-Peak Energy and Off-Peak Energy delivered by the Limited Partnership to the Point of Interconnection and received by Hydro during any particular time period in the Hydro Financial Year, shall for the purposes of this Agreement, including Sections 2.2 and 2.3, be determined to be equal to:

(a) the quantum of energy measured by metering equipment at or near the Point of Interconnection, in accordance with Sections 4.3, 4.4, 4.5,4.6 and 4.7 for any particular period of time; reduced by

(b) the Hydro High Voltage Transmission System Energy Losses applicable for that period of time.

4.2 **Transmission System Losses**

The Hydro High Voltage Transmission System Energy Losses for any particular period in the Hydro Financial Year shall be determined by Hydro and provided to the Limited Partnership within ten (10) Business Days of the last day of the particular period and shall be expressed as a percentage equal to:

(a) the energy generated and delivered to Hydro's High Voltage Transmission System for that particular period of time during that applicable Hydro Financial Year, from all of the hydraulic and thermal electric generation facilities that form part of the Integrated Power System, (which shall be determined by Hydro measuring the generation and delivery of that energy expressed in GWh); less

(b) the energy delivered from the Hydro High Voltage Transmission System, during that particular period of time in the Hydro Financial Year, to other parts of the Integrated Power System, (which shall be determined by Hydro measuring that energy at exit points, selected by Hydro, from the Hydro High Voltage Transmission System, expressed in GWh); divided by

(c) the amount determined in 4.1.

4.3 Metering Equipment.

Subject to Section 4.6 Hydro shall provide, install, operate, maintain and own and/or control metering equipment of revenue quality (the "**Hydro Metering Equipment**"), for the Wuskwatim Generating Station at or near the Point of Interconnection the exact location of which shall be determined by Hydro. The Limited Partnership shall reimburse Hydro for all actual costs and expenses incurred by Hydro under this Article IV, including those associated with the operation, maintenance and administration of the Hydro Metering Equipment and the provision of metering data to the Limited Partnership.

4.4 Operation and Maintenance of Metering Equipment

The Hydro Metering Equipment shall be installed, calibrated, repaired, replaced, maintained and tested in accordance with the provisions of the *Electricity and Gas Inspection* Act (Canada) as amended from time to time and any reasonable guidelines, procedures, decisions, practices and policies of Hydro. The Limited Partnership shall provide and maintain without charge, convenient, accessible and safe space at or near the metering point for Hydro Metering Equipment, which shall be in the care of and at the risk of the Limited Partnership. Unless Hydro shall otherwise advise the Limited Partnership, Hydro shall in accordance with any guidelines, procedures, decisions, practices and policies of Hydro read the meters and supply such meter readings to the Limited Partnership no later than the end of the third Business Day of each month. Metering records shall be available at all reasonable times to the Limited Partnership.

4.5 Hydro Access to and Testing of Metering Equipment

Authorized employees and agents of Hydro shall at reasonable times have free and uninterrupted access to the Wuskwatim Project for the purpose of reading and conducting tests on the Hydro Metering Equipment. Hydro may test, calibrate, maintain, remove and replace the Hydro Metering Equipment at any time. Hydro shall at the Limited Partnership's expense, inspect and test the Hydro Metering Equipment upon installation and at least once every two (2) years, thereafter. If requested to do so by the Limited Partnership, Hydro shall inspect or test metering equipment more frequently than every two (2) years. Hydro shall give reasonable notice of the time when any inspection or test shall take place, and the Limited Partnership may have representatives present at the test or inspection. Unless provided otherwise by the *Electricity and Gas Inspection Act* (Canada) or other Laws, if Hydro Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at the Limited Partnership's expense, in order to provide accurate metering. If Hydro Metering Equipment fails to register, or if the measurement made by Hydro Metering Equipment during a test varies by more than one percent (1%) from the measurement made by the standard meter used in the test, adjustment shall be made correcting all measurements made by the inaccurate meter for (i) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (ii) the period immediately preceding the test of the Hydro Metering Equipment equal to one-half the time period from the date of the last test of the Hydro Metering Equipment provided that the period covered by the correction shall not exceed six months. Hydro shall provide copies of its metering tests to the Limited Partnership, which shall provide the information to TPC at least biannually.

4.6 Alternate Metering Equipment.

Hydro may on notice to the Limited Partnership advise that it shall not install its own metering equipment in accordance with the provisions of Sections 4.3, 4.4 and 4.5) and shall for the purposes of Sections 4.1 and 4.2, have the quantum of energy determined by the metering equipment installed, operated, maintained, owned and/or controlled by Hydro (Transmission and Development Business Unit) pursuant to the provisions of the Interconnection and Operating Agreement. The Parties agree that in the event Hydro provides this notice that the metering data provided to the Limited Partnership pursuant to the provisions of the Interconnection and Operating Agreement shall be used for the purposes of determining the quantum of energy delivered to the Point of Interconnection.

4.7 IOA Inspections and Testing

The Parties also agree to be bound by the inspection and testing provisions of the Interconnection and Operating Agreement and to any adjustments or corrections that are made in accordance with the provisions of that agreement to the metering measurements and data and Hydro shall be entitled to receive all metering data and records that the Limited Partnership receives pursuant to the provisions of the Interconnection and Operating Agreement. Hydro shall also be entitled to attend with the Limited Partnership at all testing of the metering equipment under the provisions of the Interconnection and Operating Agreement. The Limited Partnership agrees to cause the metering equipment to be inspected or tested in accordance with the provisions of the Interconnection and Operating Agreement if Hydro so requests. Hydro shall retain its right on reasonable notice to the Limited Partnership to install the Hydro Metering Equipment in accordance with Sections 4.3, 4.4 and 4.5 at a subsequent date and to have those provisions apply for the determination of the quantum of energy delivered to the Point of Interconnection.

ARTICLE V
ENERGY RATE ADJUSTMENTS

5.1 Report on Long-Term Transactions and Opportunity Transactions.

Hydro shall provide the Limited Partnership within thirty (30) days of the last day of each Hydro Financial Year with a written report of the amount of energy (expressed in GWh) that was bought or sold pursuant to the Long-Term Transactions that were used to calculate the Long-Term Transaction Rate for that Hydro Financial Year and the amount of energy (expressed in GWh) that was bought or sold pursuant to the Opportunity Transactions that were used to calculate the Opportunity Transaction Rate for that Hydro Financial Year. Such report shall also include particulars of the Adjustments made by Hydro pursuant to Section 2.4

5.2 Insufficient Transaction in Respect of Long-Term Transaction Rate.

If the report prepared by Hydro pursuant to Section 5.1 in respect of a particular Hydro Financial Year discloses there were Insufficient Transactions in respect of the Long-Term Transaction Rate for that Hydro Financial Year, then, subject to an Energy Rate Review brought pursuant to Article XVII of the PDA the compensation to be paid by Hydro for the On-Peak Energy received by Hydro at the Point of Interconnection on a Canadian Dollar per MWh basis during that Hydro Financial Year (the "**Insufficient Long-Term Transaction Year**") shall be based on a rate that is equal to the actual weighted average price over the Insufficient Long-Term Transaction Year that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid, for the energy and capacity purchased or sold by Hydro pursuant to all applicable On-Peak Opportunity Transactions during the Insufficient Long-Term Transaction Year (the "**On-Peak Opportunity Transaction Rate**") determined in the following manner:

(a) only those On-Peak Opportunity Transactions or portions thereof applicable to the time period where the energy sold or purchased physically crossed the Manitoba border and were delivered during the Insufficient Long-Term Transaction Year, as determined by Hydro in accordance with Good Utility Practice, (the "**Applicable On-Peak Opportunity Transactions**") shall be included in determining the actual weighted average price over the Insufficient Long-Term Transaction Year;

(b) Hydro, acting reasonably, in addition to all other allocations or adjustments that may be required, shall include the portion of the price, if any, that is payable for capacity, which is attributable to that portion of the energy that physically crossed the Manitoba border and was delivered during the Insufficient Long-Term Transaction Year for each of the Applicable On-Peak Opportunity Transactions in determining the actual average weighted price over the Insufficient Long-Term Transaction Year;

(c) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable On-Peak Opportunity Transactions shall be adjusted to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable On-Peak Opportunity Transactions. The charges or credits will include actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement;

(d) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable On-Peak Opportunity Transactions shall be determined in Canadian Dollars per MWh and if Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid in U.S. Dollars pursuant to any of the Applicable On-Peak Opportunity Transactions, the amounts shall be converted to Canadian Dollars (after the Adjustments referred to in Section 2.4) by reference to the average Equivalent Canadian Dollar Amount for the month, during which the said obligation to pay, or the entitlement to be paid the said amount arises; and

(e) the On-Peak Opportunity Transaction Rate shall be expressed in Canadian dollars per MWh and shall be calculated by dividing (i) the total net amount that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, pursuant to the Applicable On-Peak Opportunity Transactions, determined in accordance with this Section 5.2; by (ii) the total energy that was imported or exported by Hydro pursuant to the Applicable On-Peak Opportunity Transactions, determined in accordance with this Section 5.2.

If as a result of an Energy Rate Review pursuant to Article XVII of the PDA, the compensation to be paid by Hydro for the On-Peak Energy received by Hydro during the Insufficient Long-Term Transaction Year is greater than or less than the compensation determined in accordance with this Section 5.2, then Hydro shall prepare a reconciliation of the amount owing to the Limited Partnership by Hydro or that Hydro has overpaid. The reconciliation shall adjust for all amounts that the Limited Partnership is required to pay to Hydro, that is based on or is otherwise determined from the Energy Calculation paid by Hydro to the Limited Partnership for the delivery of the Net Actual Generation, including the fee to be paid pursuant to Section 3.1(j). On completion of the reconciliation any amount overpaid by Hydro, shall immediately be paid by the Limited Partnership to Hydro, without interest, unless Hydro agrees in writing to receive same as a credit on account of any amount otherwise required to be paid pursuant to the provisions of this Agreement and any additional amount owing by Hydro shall immediately be paid by Hydro to the Limited Partnership without interest.

5.3 Insufficient Transactions in Respect of the Opportunity Transaction Rate.

If the report prepared by Hydro pursuant to Section 5.1 in respect of a particular Hydro Financial Year discloses there were Insufficient Transactions in respect of the Opportunity Transaction Rate for that Hydro Financial Year, then, the compensation to be paid by Hydro for the Off-Peak Energy received by Hydro during that Hydro Financial Year and for all subsequent years shall, subject to any future Energy Rate Review, be determined pursuant to the Energy Rate Review, brought pursuant to Article XVII of the PDA.

5.4 Adjustment of Energy Rate.

The Energy Rate payable under this Agreement shall be adjusted to accord with the agreement of the Parties or the decision of an Expert made pursuant to an Energy Rate Review and Transaction Rate Review. Forthwith after any agreement or decision which has retroactive effect, Hydro shall prepare a reconciliation of the amount that is owing to the Limited Partnership by Hydro or the amount that Hydro has overpaid. The reconciliation shall adjust for all amounts that the Limited partnership is required to pay to Hydro, that is based on or is otherwise determined from the Energy Calculation paid by Hydro to the Limited Partnership adjust for all amounts that the Limited partnership is required to pay to Hydro, that is based on or is otherwise determined from the Energy Calculation paid by Hydro to the Limited Partnership for the delivery of the Net Actual Generation, including the fee required to be paid pursuant to Section 3.1(j). On completion of the reconciliation any amount overpaid by Hydro, shall immediately be paid by the Limited Partnership to Hydro, without interest, unless Hydro agrees in writing to receive same as a credit on account of any amount otherwise required to be paid to the Limited Partnership pursuant to the provisions of this Agreement and any additional amount owing by Hydro shall immediately be paid by Hydro to the Limited Partnership without interest.

ARTICLE VI
ENERGY RATE REVIEWS AND TRANSACTION RATE REVIEWS

6.1 Energy Rate Review.

The Long-Term Transaction Rate and the Opportunity Transaction Rate used to determine the Energy Rate have been agreed to as a proxy or reasonable substitute to capture the enhanced value of the energy and capacity to Hydro in the electricity markets available to Hydro outside of Manitoba and the recovery of associated costs related to the purchase of the energy and capacity from the Limited Partnership and the resale in the electricity markets available to Hydro outside of Manitoba. The Energy Rate has been arrived at based on industry practices existing as at the date of this Agreement for the pricing of different types of transactions for different classes or categories of energy. Industry practices may change during the Term, possibly significantly. For this reason, the Pricing Principles and Pricing Criteria described in Sections 6.2 and 6.3 have been established to apply to any Energy Rate Review. Subject to Sections 6.2 and 6.3, the

Energy Rate may be reviewed from time to time in the manner provided in Article XVII of the PDA.

6.2 Pricing Principles.

The rate Hydro is to pay for the capacity, of and the energy generated by, the Wuskwatim Project will be based on the value of the energy and capacity to Hydro at the Manitoba border in the electricity markets available to Hydro outside of Manitoba. During the ten year period from 2014/15 to 2023/24, the Domestic Transaction Rate will form a portion of the rate Hydro will pay the Limited Partnership. In the years after the NCN Total Outstandings and TPC Total Outstandings are repaid in full, the Fee will be implemented in place of all fees that would have been payable under the terms of the Initial PPA had it remained in effect. These principles shall be collectively known as "the **Pricing Principles**" for purposes of any Rate Review.

6.3 Pricing Criteria.

During an Energy Rate Review the following pricing criteria (the "**Pricing Criteria**") shall be applicable:

(a) the rate will recognize: (i) the effects of applicable constraints and regulations that may limit access to the electricity markets outside of Manitoba; and (ii) any other risks or actual costs to Hydro, associated with or applicable to the purchase of the energy and capacity of the Wuskwatim Project from the Limited Partnership and the resale of that energy and capacity in electricity markets outside of Manitoba (to the extent Hydro has not been compensated for these risks or costs pursuant to other provisions of this Agreement);

(b) in determining the value of the energy and capacity of the Wuskwatim Project the rate will recognize that the Wuskwatim Project is operated by Hydro as part of the Integrated Power System and although Hydro, as purchaser, accepts the energy from the Wuskwatim Project as it is produced on an hourly basis, Hydro through its operation of the Integrated Power System is able to allocate portions of the energy into other time periods;

(c) if Hydro is exporting or importing energy to or from electricity markets outside of Manitoba in reasonable quantities (the determination of which is not restricted by the quantum referenced for Insufficient Transactions), the price that Hydro obtained at the Manitoba border for the export or import of the energy that physically crossed the Manitoba border pursuant to the export or import transactions net of all Adjustments ; and

(d) if Hydro is not exporting or importing energy and capacity in reasonable quantities (the determination of which is not restricted by the quantum referenced for Insufficient Transactions), then, subject to Section 6.3(a)(ii), the determination of value to Hydro will be made based on the price that Hydro could have obtained at the Manitoba border if it was exporting energy and capacity to electricity markets available to Hydro outside of Manitoba net of all Adjustments.

6.4 Transaction Rate Review.

The Adjustments made by Hydro may be reviewed in the manner provided in Article XVII of the PDA.

ARTICLE VII
REPRESENTATIONS AND WARRANTIES

7.1 Representations and Warranties of the Limited Partnership.

The Limited Partnership represents and warrants that each of the following representations and warranties is true and accurate:

(a) the Limited Partnership is a limited partnership duly formed, validly existing and in good standing under the laws of the Province of Manitoba and has all requisite power and authority to own, operate or lease the properties owned or to be owned, operated or leased by the Limited Partnership and to carry on its business as contemplated by the Limited Partnership Agreement; and

(b) this Agreement has been duly authorized, executed and delivered by the General Partner by or on behalf of the Limited Partnership and is a legal, valid and binding obligation of the Limited Partnership and of the General Partner enforceable against each of them by Hydro in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or by this Agreement, at the discretion of the Arbitrator.

7.2 **Survival of Representations and Warranties of the Limited Partnership.**

All the representations and warranties of the Limited Partnership in Section 7.1 shall survive the execution and delivery of this Agreement and shall continue in full force and effect notwithstanding any investigation made at any time by or on behalf of Hydro.

7.3 **No Representations by the Limited Partnership.**

No other representation, warranty or other statement made by the Limited Partnership in respect of this Agreement shall be binding on the Limited Partnership unless made by it in writing as a specific amendment to this Agreement.

7.4 **Representations and Warranties of Hydro.**

Hydro represents and warrants that each of the following representations and warranties is true and accurate:

(a) Hydro is a corporation duly incorporated and organized and validly subsisting under the laws of the Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and to perform its obligations hereunder, subject to the provisions of the *Hydro Act*; and

(b) this Agreement has been duly authorized, executed and delivered by Hydro and is a legal, valid and binding obligation of Hydro enforceable against Hydro by the Limited Partnership in accordance with its terms, except as enforcement may be limited by the provisions of the *Hydro Act* and by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or, by this Agreement, at the discretion of the Arbitrator.

7.5 Survival Representations and Warranties of Hydro.

All the representations and warranties of Hydro contained in Section 7.4 shall survive the execution of this Agreement and shall remain in full force and effect notwithstanding any investigation made at any time by or on behalf of the Limited Partnership.

7.6 No Representations by Hydro.

No other representation, warranty or other statement made by Hydro in respect of this Agreement shall be binding on Hydro unless made by it in writing as a specific amendment to this Agreement.

ARTICLE VIII
BILLING, PAYMENTS AND ADJUSTMENTS

8.1 Billings, Payments and Adjustments

(1) All billings shall be calculated monthly at the end of each calendar month and reconciled monthly and yearly in accordance with provisions of this Agreement.

(2) The Limited Partnership shall deliver all bills to Hydro monthly within twenty-one (21) calendar days after the end of the period covered by the bill. The period for billing shall be from 12:01 a.m. (Winnipeg time) of the first calendar day of the month to 12:01 a.m. (Winnipeg time) of the first calendar day of the succeeding month Bills shall be considered rendered upon receipt by Hydro. If all information necessary is not accurately known in time for the preparation of the monthly bill, estimates may be used to prepare an interim bill with a final bill to be prepared when accurate information becomes known.

(3) All bills shall be due and payable in immediately available same-day funds within five (5) Business Days from the date the bill is rendered. If such due date falls on a non-Business Day, the payment shall be due and payable on the next following Business Day. Payments received after the due date shall be considered late. Late payments shall include a fee equal to

the amount determined by applying interest at the prime rate established by the Limited Partnership's bank plus two percent (2%) per annum to the overdue amount billed for the period the payment is late.

(4) If a Party disputes all or any part of a bill, that Party shall pay the amount of the bill not in dispute to the other Party and shall pay into an account specified by Hydro that portion of the bill in dispute, pending resolution of such dispute. If the resolution of a dispute regarding a bill results in a refund, interest thereon shall accrue at whatever rate of interest is applicable to the account into which the disputed amount has been deposited.

(5) Payment of all bills shall be made by interbank wire transfer to the Limited Partnership bank in accordance with the account instructions as provided by the Limited Partnership and payment shall be deemed made when received by the designated bank.

(6) Hydro shall bill the Limited Partnership for all actual costs and expenses which it incurs in connection with this Agreement. The Limited Partnership's payment to Hydro under this paragraph shall be made within five (5) Business days following receipt of the written bill from Hydro. Payments made after the due date shall be considered late and shall bear interest on the unpaid balance at an annual rate of the Limited Partnership's bank's prime interest rate plus two percent (2%) per annum.

(7) Hydro shall have the right to set-off and/or recoup against payments to be made to the Limited Partnership by the terms of this Agreement any amount reasonably believed by Hydro to be due to Hydro from the Limited Partnership under Section 3.1(j) and under Section 9.3(b). Hydro's exercise of its right of retention under this section is without prejudice to the Limited Partnership's right to contest the set-off and the claim upon which the set-off is based. Where Hydro exercises its right of set-off or recoupment, Hydro shall notify the Limited Partnership in writing of the specific basis for the set-off or recoupment in reasonable detail, including the basis for calculation of the amount believed to be due to Hydro.

ARTICLE IX

SPILL ENERGY REVENUE ADJUSTMENT

9.1 Article IX Definitions.

For purposes of this Article IX, defined terms shall have the following meanings:

"**Average On-Peak Energy Price**" means the average Energy Rate paid by Hydro to the Limited Partnership for On-Peak Energy, calculated on an annual basis, pursuant to this Agreement for a particular Hydro Financial Year less:

(a) Transmission Costs;

(b) the Fee, if applicable; and

(c) Water Rental Charges.

"**Average Off-Peak Energy Price**" means the average Energy Rate paid by Hydro to the Limited Partnership for Off-Peak Energy, calculated on an annual basis, pursuant to this Agreement for a particular Hydro Financial Year less:

(a) Transmission Costs;

(b) the Fee, if applicable; and

(c) Water Rental Charges.

"**CRD**" means the diversion of water from the Churchill River to the Nelson River and the impoundment of water on the Rat River and Southern Indian Lake as authorized by the CRD Licence;

"**CRD Licence**" means the interim or final licence and associated approvals to operate the CRD granted from time to time by Manitoba to Hydro under *The Water Power Act* (Manitoba);

"**CRD Wuskwatim Spill Energy**" means the total energy in GWh that could have been generated at the Wuskwatim Generating Station within each Hydro Financial Year as On-Peak

Spill Energy and as Off-Peak Spill Energy, respectively, had excess water not been spilled at Missi Falls calculated in accordance with Section 9.2.

"**Fee**" means the fees payable by the Limited Partnership to Hydro under Section 3.1(j) of this Agreement.

"**Missi Falls**" means the Missi Falls Control Station operated by Hydro.

"**Missi Falls Minimum Flow**" means the minimum discharge requirement as specified in the licences issued to Hydro for Missi Falls under the CRD Licence or other licence, permit or regulatory provisions applicable to the operation of Missi Falls from time to time.

"**Notigi**" means the Notigi Control Station operated by Hydro.

"**Notigi Maximum Flow**" means the maximum discharge requirement as specified in the licences issued to Hydro for Notigi under the CRD Licence or other licence, permit or regulatory provisions applicable to the operation of Notigi from time to time.

"**Off-Peak Spill Energy**" means that portion of CRD Wuskwatim Spill Energy, measured in MWh, that would have been generated as Off-Peak Energy minus 1.73 GWh or such other amount of energy to be deducted as determined in a Rate Review.

"**On-Peak Spill Energy**" means that portion of CRD Wuskwatim Spill Energy, measured in MWh, that would have been generated as On-Peak Energy minus 0.87 GWh or such other amount of energy to be deducted as determined in a Rate Review.

"**Spill Energy Revenue Adjustment**" means the amount calculated pursuant to Section 9.3.

"**SPLASH Modelling**" means the results Hydro generated as at the Hydro Financial Year ending on March 31, 2005 under its computer model (Simulation Program for Long-term Analysis of System Hydraulics) to simulate the operation of the Integrated Power System under a series of flow conditions with the objective of meeting a forecast of load requirements and maximizing revenues while recognizing limitations imposed by licences and agreements.

"**Transmission Costs**" means costs related to the transmission of Net Actual Generation received by Hydro at the Point of Interconnection on the Hydro Transmission System.

"**Water Rental Charges**" means the Water Rental charges payable to the Province of Manitoba, under *The Water Power Act* (Manitoba), for use of water for the Wuskwatim Project.

"**Wuskwatim GS Spill**" means a spill or release of water at the Wuskwatim Project as a result of operating conditions.

9.2 CRD Wuskwatim Spill Energy Calculation.

The CRD Wuskwatim Spill Energy shall be the sum of the On-Peak Spill Energy and the Off-Peak Spill Energy and shall be determined:

(a) based on an amount of water flow equal to the lesser of:

(i) Missi Falls flow in excess of the Missi Falls Minimum Flow; if the value is less than zero, the value shall equal zero;

(ii) Notigi Maximum Flow in effect at the time minus the actual Notigi flow, if the value is less than zero, the value shall equal zero;

(iii) zero during any period during which a Wuskwatim GS Spill occurs; and

(iv) zero during any period in which Hydro is unable to accept energy generated at the Wuskwatim Generating Station due to domestic transmission constraints per Section 2.18 of this Agreement;

(b) with allowance for:

(i) Missi Falls flow in excess of the Missi Falls Minimum Flow considered necessary by Hydro, acting in accordance with Good Utility Practice, to manage wind effects, ice formation, emergency conditions, control structure manual operability constraints, or other relevant factors; and

(ii) Notigi flow below Notigi Maximum Flow considered necessary by Hydro, acting in accordance with Good Utility Practice, to manage wind effects, operation to manage ice formation, emergency conditions, control structure manual operability constraints, all other relevant factors;

(c) provided that if Wuskwatim generation units are out of service or derated, the calculation of CRD Wuskwatim Spill Energy shall be reduced by the amount of energy that potentially could have been generated if generation units were not out of service or derated.

9.3 Revenue Adjustment Calculation.

Within one hundred twenty (120) days of the end of each Hydro Financial Year, commencing in the Hydro Financial Year ending March 31, 2015, Hydro shall provide the Limited Partnership and the Limited Partners with a calculation of the CRD Wuskwatim Spill Energy and the following information:

(a) the CRD Wuskwatim Spill Energy for the immediately preceding Hydro Financial Year;

(b) the particulars of the calculation of the CRD Wuskwatim Spill Energy, the Average On-Peak Energy Price, the Average Off-Peak Energy Price, the On-Peak Spill Energy Amount, if any, and the Off-Peak Spill Energy Amount, if any, for that Hydro Fiscal Year; and

(c) the data and methodologies which formed the basis of the calculations, in reasonable detail so each Limited Partner can verify the calculations.

9.4 Payment of Revenue Adjustment.

Within thirty (30) days of providing the information in Section 9.3:

(a) if the CRD Wuskwatim Spill Energy is a number greater than zero, Hydro shall pay to the Limited Partnership an amount equal to the sum of:

(i) the product of the On-Peak Spill Energy and the Average On-Peak Energy Price; and

(ii) the product of the Off-Peak Spill Energy and the Average Off-Peak Energy Price.

(b) if the CRD Wuskwatim Spill Energy is a number less than zero, the Limited Partnership shall pay to Hydro an amount equal to the sum of:

(i) the product of the On-Peak Spill Energy Amount, negative one (-1.0), and the Average On-Peak Energy Price; and

(ii) the product of the Off-Peak Spill Energy, negative one (-1.0), and the Average Off-Peak Energy Price.

Hydro may set-off any amount payable by the Limited Partnership pursuant to Section 9.4 against any amounts Hydro is obligated to pay the Limited Partnership pursuant to this Agreement.

9.5 Spill Energy Amount and Revenue Adjustment Review.

The Parties agree that the CRD Wuskwatim Spill Energy and the data and methodologies which formed the basis of the calculations used in determining the Spill Energy Revenue Adjustment may be reviewed from time to time in the manner provided for in Article XVII of the PDA. The Parties agree that the principles to be considered in a Rate Review of the CRD Wuskwatim Spill Energy and the Spill Energy Revenue Adjustment are that:

(a) the Parties intend the Limited Partnership receives or pays an annual adjustment that would make the annual total revenue of the Limited Partnership equal to that which it would have received if the CRD Wuskwatim Spill Energy equaled the average amount of spill energy predicted by the SPLASH Modelling for Hydro's Financial Year ending March 31, 2005; and

(b) the Fee and the Water Rental Charges in effect at the date of each adjustment shall be subtracted from the amount of the adjustment.

ARTICLE X
EVENTS OF DEFAULT

10.1 Event of Limited Partnership Default

If any of the following events, conditions or circumstances (each an "**Event of Limited Partnership Default**") shall occur and be continuing, then Hydro by written notice to the Limited Partnership shall be entitled to terminate the obligations of Hydro under this Agreement:

(1) any representation or warranty or certification made or deemed to be made by the Limited Partnership pursuant to or in connection with this Agreement delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(2) an Arbitrator makes a determination that the Limited Partnership failed to perform or observe any term, covenant or agreement contained in this Agreement, on its part to be performed or observed and such failure shall remain unremedied after the end of the period within which the Arbitrator determines the Limited Partnership is required to remedy such failure;

(3) (the Limited Partnership shall:

(a) become insolvent or generally not pay its debts as such debts become due;

(b) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(c) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(d) institute or have instituted against it any proceeding seeking:

(i) to adjudicate it a bankrupt or insolvent;

(ii) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iii) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of the Limited Partnership's Property;

(iv) and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within 30 days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of the Limited Partnership's Property) shall occur; or

(v) take any action to authorize any of the foregoing actions;

(4) Notice is sent to or received by the Limited Partnership from any creditor with respect to the intention of such creditor to enforce a lien on any Property of the Limited Partnership unless such Notice is being contested in good faith by appropriate legal proceedings and such Notice has not resulted in, or does not involve, any immediate danger of the sale, forfeiture or loss of any of the Property of the Limited Partnership that is the subject of such Notice;

(5) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Authority which may be reasonably likely to require the Limited Partnership to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against the Limited Partnership, and either:

(a) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

(b) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(6) the loss, suspension or failure to renew any Licence or any other licence or permit held by the Limited Partnership or any agreement to which the Limited Partnership is a party the effect of which would prohibit or otherwise restrict the Limited Partnership from conducting all or a material part of the Business; or

(7) the occurrence of a Material Adverse Business Effect.

10.2 Expense of Hydro

Upon the occurrence of any Event of Limited Partnership Default, which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Limited Partnership Default. All reasonable expenses and costs, charges incurred by or on behalf of Hydro in connection with any remedial action taken pursuant to this Section 10.2 shall be a cost to be paid to Hydro by the Limited Partnership in accordance with provisions of this Agreement.

10.3 Event of Hydro Default

If any of the following events, conditions or circumstances (each an "**Event of Hydro Default**") shall occur and be continuing then the Limited Partnership by written notice to Hydro shall be entitled to terminate the obligations of the Limited Partnership under this Agreement:

(1) an Arbitrator makes a determination that Hydro failed to perform or observe any term, covenant or agreement contained in this Agreement on its part to be performed or observed and such failure shall remain

unremedied after the end of the period within which the Arbitrator determines Hydro is required to remedy such failure; or

(2) Hydro shall:

(a) become insolvent or generally not pay its debts as such debts become due;

(b) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(c) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(d) institute or have instituted against it any proceeding seeking:

(i) to adjudicate it a bankrupt or insolvent;

(ii) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors; or

(iii) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property;

(iv) and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within 30 days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; or

(v) take any corporate action to authorize any of the foregoing actions;

then, in any such event, the Limited Partnership shall by written notice to Hydro be entitled to terminate the obligations of the Limited Partnership under this Agreement.

10.4 Expense of the Limited Partnership

Upon the occurrence of any Event of Hydro Default, which has not been waived and is continuing, the Limited Partnership may take any action the Limited Partnership considers advisable, acting reasonably, to remedy the effect of such Event of Hydro Default. All reasonable expenses and costs, charges incurred by or on behalf of the Limited Partnership in connection with any remedial action taken pursuant to this Section 9.4 shall be a cost to be paid to the Limited Partnership by Hydro in accordance with provisions of this Agreement.

10.5 Remedies Cumulative

The remedies provided for in this Agreement are cumulative and do not exclude any other right or remedy provided by Law.

ARTICLE XI
DISPUTE RESOLUTION

11.1 General.

Subject to Section 11.2, all disputes, differences or claims, or apprehended disputes or claims which arise under this Agreement relating to the application, interpretation, meaning, alleged violation, performance or non-performance of this Agreement shall be settled by final and binding arbitration conducted pursuant to the provisions of this Article XI.

11.2 Limitation.

The provisions of this Article XI do not apply to a Rate Review which reviews shall be conducted pursuant to the provisions of Article XVII of the PDA. Notwithstanding the provisions of this Article XI an Arbitrator appointed pursuant to this Article XI shall have no jurisdiction to consider or review any matters referred to or referable to an Expert under Article XVII of the PDA, except with respect to the enforcement of a decision of such Expert made in accordance with the provisions of Article XVII of the PDA.

11.3 Endeavour to Resolve.

The Parties agree that prior to bringing any dispute, difference or claim to arbitration pursuant to the provisions of this Article XI, they shall use reasonable efforts to resolve such dispute, difference or claim amongst themselves.

11.4 Arbitration.

A Party (an "**Applicant**") who wants to settle a dispute difference or claim or apprehended dispute, difference or claim referred to in Section 11.1 (a "**Dispute**")) shall provide the other Party a written notice (a "**Dispute Notice**") which shall contain the following:

(a) the name of the respondent and interested parties;

(b) a detailed description of the Dispute; and

(c) the relief, remedy, redress or declaratory order sought.

A Dispute Notice shall be delivered within 180 days from when the Applicant knew or reasonably ought to have known of the existence of a Dispute, subject to the written agreement of the Parties to extend this time limit. An Applicant who fails to deliver a Dispute Notice with respect to a Dispute within the prescribed period shall be deemed to have waived and abandoned the Dispute.

11.5 Reply.

The Party who receives a Dispute Notice (a "**Respondent**") shall, within 60 days of receiving the Dispute Notice, provide the Applicant with a written reply (a "**Reply**"), which sets out in detail the Respondent's position with respect to the Dispute.

11.6 Referral to Arbitration.

Within 30 days of the Applicant's receipt of the Reply, if the Dispute has not been settled, the Dispute shall be referred to binding arbitration pursuant to the provisions of *The Arbitration Act* (Manitoba) and the following sections of this Article XI, provided that if there is any inconsistency between the provisions of the said Act and Section 11, this Agreement shall apply.

11.7 Appointment of Arbitrator.

Subject to Section 11.8, an Arbitrator shall be appointed to adjudicate the dispute, using the following procedure:

(1) the Applicant shall provide to the Respondent and the Respondent shall provide to the Applicant the names, addresses and occupations of not more than three individuals, each of whom it would accept as an Arbitrator;

(2) if any one of the persons on the list of proposed arbitrators is acceptable to the Applicant and the Respondent and is willing and able to act as the Arbitrator, then that person shall be appointed as the Arbitrator forthwith; and

(3) if within 45 days of the referral of the Dispute to the binding arbitration the Applicant and the Respondent cannot agree upon a person to act as Arbitrator, either of them may request that the Arbitrator be appointed by the Chief Justice or the Associate Chief Justice of the Court of Queen's Bench (Winnipeg Division) by application to the said court served on the other Party to the arbitration.

11.8 Qualifications of Arbitrator.

An Arbitrator appointed pursuant to Section 11.7 shall:

(a) be qualified to decide the particular question in dispute;

(b) not have a pecuniary interest in the particular matter in dispute; and

(c) not have, within a period of one year prior to the date on which the matter was referred to arbitration pursuant to Section 11.4, acted, or been a member of any firm that has acted as solicitor, counsel or agent for any of the Parties.

11.9 Length of Hearing.

The Arbitrator once appointed shall proceed expeditiously to hear and determine the question or questions in dispute as set out in the Dispute and Reply, subject to any reasonable delay due to, or resulting from, any unforeseen circumstances.

11.10 Place of Hearing.

The arbitration shall take place at such location, place and time as the Parties may agree or as the Arbitrator shall fix. The law applicable to the arbitration shall be the Laws of Manitoba and the Laws of Canada applicable in Manitoba.

11.11 Powers of the Arbitrator.

The Arbitrator may determine all questions of law, fact and jurisdiction and all matters of procedure relating to the arbitration. The Arbitrator shall have the right to grant all legal and equitable relief necessary to provide a final and conclusive resolution of the Dispute including, without limitation, the right to relieve, on just and equitable terms, if applicable, against breaches of time limits set out in this Agreement, the right to determine, if applicable, the monetary value of any loss or injury suffered by a Party and to make an order directing a Party to pay the monetary value of any loss or injury so determined and to award costs (including legal fees and the costs of the arbitration) and interest. Except as the Parties otherwise expressly agree, the Arbitrator shall not have the authority or jurisdiction to change, alter, or amend this Agreement or any term or provision contained therein.

11.12 Counsel.

The Parties may be represented by counsel.

11.13 Evidence.

Evidence submitted in arbitration may be presented in writing or orally. The Parties at a minimum shall disclose all relevant information and documents as would be compellable in a court of law. The Arbitrator may require relevant information and documents to be disclosed by either Party, either prior to or during a hearing, except such documents as would not be compellable if the action were brought in a court of law.

11.14 Arbitration Award.

The Arbitrator shall deliver the award within 90 days following the completion of the hearing.

11.15 Award Final.

The decision of the Arbitrator shall be final and binding on the Parties. The right of any affected Party to appeal an award will be limited to a question of law, provided that leave is first obtained from the Court of Queen's Bench based on the criteria listed in Section 44 of *The Arbitration Act* (Manitoba).

11.16 Costs of Arbitration.

Each Party shall bear its own costs and an equal share of the costs of the Arbitrator, subject to a different award as to costs by the Arbitrator made following the completion of the Arbitration.

11.17 Performance of Obligations.

Each Party agrees to continue performing its obligations under this Agreement while any Dispute is being resolved or arbitrated, subject to any interim order to the contrary issued by the Arbitrator.

11.18 Confidentiality.

All hearings before the Arbitrator shall be closed to the public. All statements and evidence submitted for the arbitration, the decision of the Arbitrator, the fact of the arbitration itself and all other aspects regarding the arbitration shall be kept strictly confidential except as otherwise required by applicable Law or agreed to by the Parties.

11.19 Arbitrator's Undertaking.

Upon appointment, every Arbitrator shall swear or affirm an undertaking in the form set forth in Schedule A.

11.20 Vacancy.

Where a vacancy occurs in the office of the Arbitrator after the commencement of proceedings, the proceedings need not recommence but may, with the unanimous consent of the Parties continue before a replacement Arbitrator. In the absence of such unanimous consent, the arbitration must recommence as if it were a new matter before a new Arbitrator.

11.21 Days.

The word "days" wherever used in this Article XI shall mean calendar days.

ARTICLE XII
GENERAL PROVISIONS

12.1 Notices.

All Notices provided for in this Agreement shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule B hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

12.2 Indemnification.

The Limited Partnership agrees to indemnify and save harmless Hydro and its officers, directors, representatives and employees and agents from any and all claims, demands, proceedings, law suits, damages, liabilities, deficiencies, costs and expenses (including, without limitation all legal fees on a solicitor and client basis) and other professional fees and disbursements, interests, penalties and amounts paid in settlement suffered or incurred by Hydro as a result of or arising directly or indirectly out of or in contravention of any breach by the Limited Partnership of or in any inaccuracy of any representation or warranty of the Limited Partnership contained in this Agreement or in any agreement, certificate or other document delivered pursuant hereto and any breach or non-performance by the Limited Partnership of any covenant to be performed by or pursuant to this Agreement or in any agreement, certificate or other document delivered pursuant hereto.

12.3 Further Assurances.

Each Party without further consideration, shall promptly do, make, execute or deliver, or cause to be done, made, executed or delivered, all such further acts, documents and things as the other Party may reasonably require from time to time for the purpose of giving effect to this Agreement or more effectively completing any matter provided for in this Agreement and shall take all such steps as may be reasonably within its power to implement to their full extent the provisions of this Agreement.

12.4 Time of the Essence.

Time shall be of the essence of this Agreement.

12.5 Enurement.

This Agreement shall enure to the benefit of and be binding upon the Parties and their permitted assigns.

12.6 Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

12.7 Waivers and Amendments.

Any term, covenant or condition of this Agreement may be amended only with the written consent of the Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of the date first above written.

WUSKWATIM POWER LIMITED PARTNERSHIP, by its General Partner 5022649 Manitoba Ltd.

Per:____________________________________
Name:
Title:

THE MANITOBA HYDRO-ELECTRIC BOARD

Per:____________________________________
Name:
Title:

Per:____________________________________
Name:
Title:

SCHEDULE A

ARBITRATOR'S UNDERTAKING

FORM OF OATH OR UNDERTAKING OF THE ARBITRATOR

I, , do swear and affirm that I will hear the matters referred to me as provided for by the Power Purchase Agreement and The Arbitration Act (Manitoba) in the matter of:

(State particulars of the matter)

and make a true and impartial award, according to the evidence, arguments of the parties, using my skill and knowledge.

DATED this day of , 20 .

Sworn or Affirmed before

A Commission, Notary, etc.

at ________________________

this ___ day of ______, 20_.

SCHEDULE B

NOTICES

Wuskwatim Power Limited Partnership
c/o 5022649 Manitoba Ltd.
360 Portage Avenue
P.O. 815, Station Main
Winnipeg, MB R3C 2P4
Attention: Chairman

Fax: (204) 360-6138

Manitoba Hydro
360 Portage Avenue
P.O. 815, Station Main
Winnipeg, MB R3C 2P4
Attention: Ken Tennenhouse, General Counsel

Fax: (204) 360-6147

SCHEDULE 6.1
AMENDED AND RESTATED NCN FINANCING AGREEMENT

AMENDED AND RESTATED NCN FINANCING AGREEMENT

between

NISICHAWAYASIHK CREE NATION

– and –

TASKINIGAHP POWER CORPORATION

– and –

THE MANITOBA HYDRO-ELECTRIC BOARD

Effective April 1, 2014

TABLE OF CONTENTS

NCN FINANCING AGREEMENT

Effective April 1, 2014

B E T W E E N:

NISICHAWAYASIHK CREE NATION,
(hereinafter referred to as "NCN")

- and –

TASKINIGAHP POWER CORPORATION,
(hereinafter referred to as "TPC")

- and –

THE MANITOBA HYDRO-ELECTRIC BOARD,
(hereinafter referred to as "Hydro")

The parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement, defined terms used herein shall have the following meanings:

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person.

“**Aggregate Capital Contributions**” means for any particular day, the sum of: (i) the subscription price paid for the purchase of the Units by the Limited Partners; and (ii) all other capital amounts contributed by the Limited Partners to the Limited Partnership pursuant to the provisions of the Limited Partnership Agreement.

“**Agreement**” means this financing agreement and all schedules and instruments in amendment or confirmation of it; “**hereof**”, “**hereto**” and “**hereunder**” and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; “**Article**”, “**Section**” or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement.

“**Anniversary Date**” means each anniversary of the Final Closing Date.

“**Approved Funds**” has the meaning ascribed thereto in the TPC Financing Agreement.

“**Auditors**” means such firm of chartered accountants as may be selected by the directors of TPC and approved by NCN from time to time to audit TPC, provided that such firm of chartered accountants is qualified to perform audits in Manitoba.

“**Authorization**” means, with respect to any Person, any authorization, order, permit, approval, grant, licence, consent, right, franchise, privilege, certificate, judgment, writ, injunction, award, determination, direction, decree, by-law, rule or regulation of any Governmental Entity having jurisdiction over such Person, whether or not having the force of Law.

“**Borrowing**” means a borrowing consisting of one or more Dividend Credit Advances.

“**Borrowing Notice**” has the meaning specified in Section 3.2.

“**Business**” has the meaning ascribed thereto in the TPC Financing Agreement.

"**Business Day**" means any day on which Hydro's head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba.

"**Canada**" means the Government of Canada.

"**Canadian Dollar Guarantee Rate**" means for any particular day, the closing rate of interest (expressed as a percentage rate per annum) charged on such day by Manitoba to Hydro, as a fee for Manitoba's guarantee of Hydro's Canadian Dollar borrowings.

"**Canadian Dollars**" and "**$**" each mean lawful money of Canada.

"**Canadian Ten Year Rate**" means for any particular day, the rate of interest per annum equal to:

(i) the Ten Year Canada Bond Rate, as at 10:00 a.m. (Winnipeg time), for such day; plus

(ii) the Canadian Dollar Guarantee Rate, as at 10:00 a.m. (Winnipeg time), for such day and either:

(A) plus the Canadian Ten Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread is less than the rate of interest for the Ten Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Ten Year Spread; or

(B) less the Canadian Ten Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread is greater than the rate of interest for the Ten Year Manitoba Canadian Dollar

Bond used in the calculation of the said Canadian Ten Year Spread.

"**Canadian Ten Year Spread**" means at any particular date, the difference between the Ten Year Canada Bond Rate in effect on that date and the rate of interest (expressed as a percentage rate per annum) for Ten Year Manitoba Canadian Dollar Bonds had Ten Year Manitoba Canadian Dollar Bonds been issued by Manitoba on that day at 10:00 a.m. (Winnipeg time) including commission costs, (with the rate of interest determined by Hydro obtaining three rate quotes for Ten Year Manitoba Canadian Dollar Bonds and using the median of the three rate quotes obtained).

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interest in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights, warrants or options to subscribe for or acquire an equity interest in such Person.

"**Change of Control**" means any change which results in NCN no longer directly owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of the bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC, as bare trustee for NCN, commits to vote such Capital Stock in accordance with the direction of Chief and Council of NCN), and for greater certainty the NCN Deed of Assignment does not effect a Change of Control.

"**Chief**" has the meaning ascribed thereto in the PDA.

"Chief and Council" has the meaning ascribed thereto in the PDA.

"**Claim**" means any claim of any nature whatsoever, including any demand, dispute, liability, obligation, debt, action, cause of action, suit, proceeding, litigation, arbitration, judgment, order, award, assessment and reassessment.

"**Collateral**" means TPC's Units and the Distributions thereon in respect of which Hydro has or will have or is intended to have a Lien pursuant to the Security Documents.

"**Corporate Distributions**" means, in respect of any Person, whether or not a corporation, any form of distribution of its profits, including in each case any:

(i) declaration or payment of any dividend on its Capital Stock; and

(ii) payment to purchase, redeem, retire or acquire or reduce the stated capital of any of its Capital Stock, or any option, warrant or other right to acquire any such Capital Stock, or apply or set apart any of its Property therefore.

"**Councillor**" has the meaning ascribed thereto in the PDA.

"**Council Resolution**" has the meaning ascribed thereto in the PDA.

"**Credit Facility Repayment Certification**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Cure Period**" has the meaning specified in Section 8.1(c).

"**Debt**" of any Person means, without duplication:

(i) all obligations of such Person for borrowed money or advances and all obligations of such Person evidenced by bonds, debentures, notes or similar instruments;

(ii) all obligations of such Person, contingent or otherwise, relative to the face amount of all letters of credit, whether or not drawn, and banker's acceptances issued for the account of such Person; and

(iii) all other items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of such Person as of the date at which Debt is to be determined (excluding trade payables incurred in the ordinary course of business).

"**Distributions**" means distributions of cash of the Limited Partnership to TPC and the return of any part of the Aggregate Capital Contributions by the Limited Partnership to TPC.

"**Dividends**" has the meaning ascribed thereto in the NCN Deed of Assignment.

"Dividend Credit Advances" means advances made by Hydro to NCN in Canadian Dollars under this Agreement and "**Dividend Credit Advance**" means any one of such Dividend Credit Advances.

"**Dividend Credit Facility**" means the non-revolving credit facility to be made available to NCN by Hydro in the maximum amount of the Dividend Credit Facility Commitment and in accordance with the terms hereof.

"Dividend Credit Facility Commitment" means,

(a) for the calendar year 2015 eighteen million ($18,000,000) dollars, less the sum of NCN Cash Flows From All Sources for the calendar years 2014 and 2015;

(b) in all other years, the aggregate of the amount calculated on each Anniversary Date prior to, but not including, the Maturity Date derived from the formula "(A x B) – C", where A is the Canadian Ten Year Rate on that Anniversary Date less 2.5%; B is TPC's Own Invested Cash on that Anniversary Date; and C is the aggregate amount of all Distributions from the Limited Partnership on TPC's Dividend Cash Units actually paid out to TPC (and not paid to Hydro pursuant to the irrevocable assignment and direction under the Loan Documents) in the 12-month period ending on such Anniversary Date. (For greater certainty, any Distributions on TPC's Dividend Cash Units which TPC was entitled to receive from the Limited Partnership pursuant to the provisions of the Limited

Partnership Agreement but which were paid to Hydro pursuant to the provisions of the Loan Documents or pursuant to the provisions of the TPC Financing Agreement are not, for the purposes of the determination of the Dividend Credit Facility Commitment and any availability thereunder only, included as Distributions on TPC's Dividend Cash Units received by TPC.)

"**Dividend Credit Facility Commitment Cap**" means the amount calculated as at the first Anniversary Date equal to four times (A) where, (A) is TPC's Own Invested Cash on the first Anniversary Date.

"**Event of Default**" has the meaning specified in Section 8.1.

"**Equity Credit Advances**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Equity Credit Facility**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Final Closing**" and "**Final Closing Date**" shall have the respective meanings ascribed thereto in the PDA"**Final Investment Closing**" and "**Final Investment Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

"**Financial Year**" means, in relation to TPC, the financial year of TPC determined by the board of directors of TPC.

"**Future Material Agreements**" has the meaning specified in Section 6.1(12).

"**GAAP**" means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the Canadian Institute of Chartered Accountants, or any successor Person at such time.

"**General Partner**" means 5022649 Manitoba Ltd., in its capacity as general partner of the Limited Partnership pursuant to the terms of the Limited Partnership Agreement.

"Government Funds" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Governmental Entity**" means any:

(i) federal, provincial, state, regional, municipal, local or other government, governmental or public department, central bank, court, commission, board, bureau, agency or instrumentality, domestic or foreign;

(ii) any agent, commission, board, or authority of any of the foregoing; or

(iii) any body exercising any regulatory, expropriation or taxing authority under or for the account of any of the foregoing.

"Guarantee" means an unconditional, irrevocable, continuing guarantee executed by TPC in favour of Hydro of the payment and performance by NCN of all of the Obligations on terms and conditions acceptable to Hydro, acting reasonably, and consistent with the terms of this Agreement, which Guarantee shall be delivered by TPC to Hydro at Initial Closing.

"**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the Hydro Act.

"**Hydro Account**" means such account or accounts maintained by Hydro at the Royal Bank of Canada, as Hydro from time to time notifies NCN for the purposes of this Agreement.

"**Hydro Act**" means *The Manitoba Hydro Act*, R.S.M. 1987, c. H190, as amended from time to time.

"**Hydro Liens**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Initial Closing**" and "**Initial Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

"**Initial Limited Partnership Agreement**" means the limited partnership agreement entered into between the General Partner, in its capacity as general partner, and Hydro, as limited partner, dated the 9th day of December, 2004.

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards, or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws.

"**Lien**" means, with respect to any Property, any charge, mortgage, pledge, hypothecation, security interest, lien, conditional sale (or other title retention agreement or lease in the nature thereof), lease, servitude, assignment, adverse claim, defect of title, restriction, trust, or other encumbrance of any kind in respect of such Property, whether or not filed, recorded or otherwise perfected under applicable Laws.

"**Limited Partner**" means one of Hydro or TPC, as the context requires, in its capacity as a limited partner of the Limited Partnership, and "**Limited Partners**" means both of Hydro and TPC, in their respective capacities as limited partners of the Limited Partnership.

"**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement, and continued pursuant to the Limited Partnership Agreement, for the purposes of owning and, directly or indirectly, planning, designing, constructing, operating and maintaining the Wuskwatim Project.

"**Limited Partnership Agreement**" means the third Amended and Restated Limited Partnership Agreement amending and restating the second Limited Partnership Agreement, dated April 16, 2015 between the general partner in its capacity as General Partner and Hydro and TPC, in their respective capacities as limited partners.

"**Limited Partnership Payment Certification**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Loan Documents**" means this Agreement, the Guarantee, the Security Documents, and all other agreements, certificates and instruments delivered or given pursuant to or in connection with the Dividend Credit Facility established under this Agreement; and "**Loan Document**" means any one of such Loan Documents.

"**Loss**" means any loss whatsoever, whether direct or indirect, including expenses, costs, damages, judgments, penalties, fines, charges, claims, demands, liabilities, debts, interest and any and all legal fees and disbursements, on a solicitor and his own client basis.

"**Manitoba**" means the Government of Manitoba.

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in or of itself, but which cumulatively results in a material adverse effect) on:

(i) the ability of NCN or TPC to perform any of their material obligations under the Loan Documents; or

(ii) the ability of Hydro to enforce any of the material obligations of NCN or TPC under the Loan Documents, where Hydro, acting reasonably, has determined that its ability to enforce the said material obligations cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected, notwithstanding that NCN and TPC have provided their written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said material obligations of NCN or TPC under the Loan Documents.

"**Material Agreements**" has the meaning specified in Section 5.1(k)(iii).

"**Maturity Date**" means the fiftieth Anniversary Date.

"**Member**" means a person who at the relevant time is, or has applied and is entitled to be, a member of NCN pursuant to the membership code established by and for NCN pursuant to Section 10 of the *Indian Act* (Canada), which membership code has been in force and of effect since May 24, 1988 or pursuant to a successor membership code established pursuant to legislation or lawfully adopted by NCN, and "**Members**" means the group of persons each of whom is a Member.

"**NCN**" means the Nisichawayasihk Cree Nation, formerly known as the Nelson House First Nation.

"**NCN Cash Flow From All Sources**" means, for the calendar years 2014 and 2015, the total amount of:

(a) the water rental rebate which NCN received or is entitled to receive from Manitoba for the calendar year pursuant to its water rental rebate agreement with Manitoba;

(b) the interest income on the Hydro Bonds paid or payable to in that calendar year by Hydro in accordance with the One Year Agreement or PDA Supplement No. 2;

(c) three hundred eight thousand twenty-five ($308,025) dollars paid by Hydro to NCN on March 3, 2014 as the remaining NCN Dividend Credit advance for the year 2013; and

(d) the annuity payable by Hydro to NCN for the calendar year pursuant to Article 11 of the PDA Supplement No. 2.

"**NCN Deed of Assignment**" has the meaning ascribed thereto in the PDA.

"**Notice**" means any notice, citation, directive, request for information, writ, summons, statement of claim or other communication from any Person.

"**Obligations**" has the meaning specified in Section 7.1.

"**One Year Agreement**" means the agreement dated November 28, 2013 between NCN and Hydro.

"**Over-Drawn Amount**" has the meaning specified in Section 2.5 (1).

"PDA" means the Project Development Agreement dated June 26, 2006 made between NCN, Hydro, TPC, the General Partner and the Limited Partnership as supplemented and amended by the PDA Supplement No. 1 dated March 15, 2011 and the PDA Supplement No. 2.

"**PDA Supplement No. 2**" means the second supplementary agreement dated April 16, 2015 between NCN, Hydro, Taskinigahp Power Corporation, 5022649 Manitoba Ltd. and Wuskwatim Power Limited Partnership.

"**Permitted Liens**" means, with respect to any Person, any one or more the following:

(i) Liens for Taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such taxes, assessments and charges;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(ii) Liens resulting from any judgment rendered or Claim filed against such Person which such Person shall be contesting in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such judgment or Claim;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(iii) undetermined Liens arising in the ordinary course of business which have not at such time been filed pursuant to Law against such Person or which relate to obligations not due or delinquent;

(iv) Liens arising in the ordinary course of business which are not registered against title to the Collateral and are not overdue for a period of more than thirty (30) days or which are being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion, (i) adequate security has been provided to ensure payment of such Liens; (ii) adequate reserves with respect thereto are maintained on the consolidated books of such Person in accordance with GAAP; and (iii) in each case, such Liens will not materially interfere with use of such Property by the Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(v) any Lien, payment of which has been provided for by the depositing with Hydro of an amount in cash, or the obtaining of a surety bond satisfactory to Hydro, in its absolute discretion, sufficient in either case to pay or discharge such Lien and which deposit or bond Hydro is authorized to use or draw upon for that purpose;

(vi) Liens securing Purchase Money Debt; provided that: (i) such Liens shall extend only to the specific Property of TPC acquired with the proceeds of such Purchase Money Debt (and not any other portion of the Collateral); and (ii) recourse in respect of such Liens shall be limited to such specific Property;

(vii) the Hydro Liens; or

(viii) any other Lien approved in writing in advance by Hydro in its unfettered discretion.

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture, band within the meaning of the *Indian Act* (Canada) or other entity or Governmental Entity, and pronouns have a similarly extended meaning.

"**Property**" means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including capital stock in any other Person.

"**Purchase Money Debt**" means, with respect to any Person, all obligations of such Person incurred to finance the acquisition of Property.

"**Receiver**" means a receiver, receiver and manager or other Person having similar powers or authority appointed by Hydro or by a court at the instance of Hydro in respect of the Collateral or any part thereof.

"**Repayment Notice**" has the meaning specified in Section 2.6(1).

"**Reserve**" shall have the meaning ascribed thereto in the *Indian Act* (Canada).

"Revenue Advance Consolidation Agreement" has the meaning ascribed thereto in the PDA.

"**Sale**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Security Documents**" means those agreements and other documents in favour of Hydro described in Schedule G in form and substance satisfactory to Hydro, acting reasonably, as such documents may be amended or restated from time to time, as security for all or any portion of the Obligations.

"**Subsidiary**" means, at any time, as to any Person, any corporation or other Person, if at such time the first-mentioned Person owns, directly or indirectly, securities or other ownership interests in such corporation or other Person, having ordinary voting power sufficient to elect a majority of the board of directors or persons performing similar functions for such corporation or other Person or has the power to determine the policies and conduct of the management of such corporation or other Person and for greater certainty includes a Subsidiary of a Subsidiary.

"TPC" means Taskinigahp Power Corporation, a corporation that is wholly owned by NCN beneficially, and by the Chief or a Councillor of NCN as registered owner and bare trustee for NCN.

"**TPC Financing Agreement**" means the Amended and Restated TPC Financing Agreement dated April 16, 2015 between TPC and Hydro.

"**TPC's Cash Units**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**TPC's Dividend Cash Units**" means:

(i) on the Final Investment Date, that the number of TPC's Units equal to (A) divided by (B) where (A) equals the number of TPC's Units on the Final Investment Date multiplied by TPC's Own Invested Cash as of that date; and (B) equals the sum of: (i) the aggregate amount of Equity Credit Advances which remain outstanding on that date; and (ii) TPC's Invested Cash as of that date;

(ii) on any particular day after the Final Investment Date (the "**Measurement Date**") until the date that the Equity Credit Facility (as defined in the TPC Financing Agreement) has been paid out in full, that number of TPC's Units equal to (A) divided by (B) where (A) is a product of: (i) the number of TPC's Dividend Cash Units on the Final Investment Date; multiplied by (ii) the number of TPC's Units on the Measurement Date; and (B) equals the number of TPC's Units on the Final Investment Date; and

(iii) on the date when the Equity Credit Facility has been paid out in full, all of TPC's Units shall be deemed to be TPC's Dividend Cash Units.

"TPC's Invested Cash" has the meaning ascribed thereto in the TPC Financing Agreement.

"**TPC's Own Funds**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**TPC's Own Invested Cash**" means on any day, the amount of TPC's Invested Cash on that day, excluding any portion which is not TPC's Own Funds.

"**TPC's Units**" means, at any time, all of the Units owned by TPC.

"Taskinigahp Trust" has the meaning ascribed thereto in the PDA.

"**Taxes**" means all taxes imposed by any Governmental Entity, including, real property, personal property, goods and services, sales, transfer, purchase, stumpage, registration, capital, excise, import duties, payroll, unemployment, disability, employee's income withholding, social security or withholding.

"**Ten Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of ten years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian dollar non callable Government of Canada reference bonds with a ten year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the ten year term, and using the median rate of the three rate quotes obtained).

"**Ten Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba at 100% of the principal amount for a term of ten years.

"**Total Outstandings**" means, at any time, with respect to the Dividend Credit Facility, the aggregate amount in Canadian Dollars of all outstanding Dividend Credit Advances.

"**Unit**" means one of the units in the Limited Partnership issued to and subscribed for by a Limited Partner pursuant to the Limited Partnership Agreement, and "**Units**" means all of the issued Units in the Limited Partnership.

"Wuskwatim Project" has the meaning ascribed thereto in the PDA.

1.2 Interpretation.

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, any other Loan Document or any provisions hereof or thereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(e) the expressions "the aggregate", "the total", "the sum" and expressions of similar meaning shall mean "the aggregate (or total or sum) without duplication";

(f) in the computation of periods of time, unless otherwise expressly provided, the word "from" means "from and including" and the words "to" and "until" mean "to but excluding";

(g) accounting terms not specifically defined shall be construed in accordance with GAAP. Except as otherwise mandated by changes in GAAP from time to time, the financial statements required to be delivered pursuant to this Agreement shall be prepared, and all calculations made for the purposes of this Agreement shall be made, unless otherwise provided for herein, by the application of GAAP applied on a basis consistent with the most recent audited financial statements of TPC, previously delivered to Hydro; and

(h) for the purposes of this Agreement, a Person (the "**first Person**") shall be deemed to be "**Controlled**" by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

(i) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

(ii) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person,

and "**Controlled**" and "**Controlling**" shall have the corresponding meaning.

1.3 <u>Interpretation of other Loan Documents.</u>

The provisions of Article 1.2 shall apply to the interpretation of all of the other Loan Documents unless specifically otherwise indicated therein.

1.4 <u>Severability.</u>

If any provision of this Agreement or any other Loan Document is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement or such Loan Documents and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions hereof or thereof shall be unaffected by such provision and shall continue to be valid and enforceable.

1.5 <u>Entire Agreement.</u>

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the parties relating to the subject matter hereof and entered into prior to the date of this Agreement.

1.6 Waiver.

No failure on the part of Hydro to exercise, and no delay in exercising, any right under this Agreement or any other Loan Document shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement or any other Loan Document preclude any other or further exercise thereof or the exercise of any other right, nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No notice to or demand on NCN or TPC (as applicable) in any case shall entitle it to any notice or demand in similar or other circumstances, unless such notice or demand is required under the terms of this Agreement or the applicable Loan Document. No waiver of any of the provision of this Agreement or any other Loan Document shall be effective unless it is in writing duly executed by the waiving party.

1.7 Governing Law.

This Agreement and each other Loan Document, shall be governed by, and interpreted in accordance with, the Laws of Manitoba and the Laws of Canada applicable therein.

1.8 Incorporation of Schedules.

The following schedules attached shall, for all purposes hereof, be incorporated in and form an integral part of this Agreement:

Schedule A	Repayment Notice
Schedule B	Borrowing Notice
Schedule C	Material Agreements
Schedule D	Issued and Outstanding Capital Stock and Debt
Schedule E	Liabilities
Schedule F	Address for Notice
Schedule G	List of Security Documents
Schedule H	Authorizations

It is acknowledged by Hydro that Schedules C to E (both inclusive) were delivered by NCN to Hydro on or before the Initial Closing Date for attachment to the Initial NCN Financing Agreement, which Schedules shall be deemed to form part of this Agreement.

1.9 Conflicts.

If a conflict or inconsistency exists between a provision of this Agreement and a provision of any of the other Loan Documents or any part thereof, then the provisions of this Agreement shall prevail. Notwithstanding the foregoing, if there is any right or remedy of Hydro set out in any of the other Loan Documents or any part thereof which is not set out or provided for in this Agreement, such additional right or remedy shall not constitute a conflict or inconsistency.

ARTICLE II
DIVIDEND CREDIT FACILITY

2.1 Dividend Credit Facility.

Hydro agrees, on the terms and conditions of this Agreement, to make available to NCN the Dividend Credit Facility by making such Dividend Credit Advances to NCN as may be requested by NCN hereunder at any time and from time to time in accordance with this Agreement.

2.2 Commitment and Dividend Credit Facility Limit.

(1) Hydro shall not be obliged to make any Dividend Credit Advance or Dividend Credit Advances which would cause the Total Outstandings to be greater than the Dividend Credit Facility Commitment, and commencing on the day after the twenty-fifth Anniversary Date, Hydro shall in addition not be obliged to make any Dividend Credit Advance or Dividend Credit Advances which would cause the Total Outstandings, including accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility, to be greater than the Dividend Credit Facility Commitment Cap, provided that where each of NCN and TPC is

otherwise in good standing under the Loan Documents, Hydro shall advance in accordance with the provisions of this Agreement, as a Dividend Credit Advance to NCN, upon request, the lesser of: (i) the amount requested by NCN; (ii) the amount hereunder which would, when advanced, cause the Total Outstandings to equal, but not exceed, the Dividend Credit Facility Commitment; and (iii) if the Advance is requested after the twenty-fifth Anniversary Date, the amount hereunder which would, when advanced, cause the Total Outstandings, including accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility, to equal, but not exceed, the Dividend Credit Facility Commitment Cap.

(2) The Dividend Credit Facility may be utilized by NCN commencing as of the first Anniversary Date subject to the terms and conditions of this Agreement. The Dividend Credit Advance, if any, available at the end of each Anniversary Date, in accordance with the provisions of this Agreement, must be requested within the time period between November 1 and February 1 in any year.

(3) The Dividend Credit Facility is a non-revolving credit and the principal amount of any Dividend Credit Advance that is repaid may not be re-borrowed and shall be a permanent reduction of the Dividend Credit Facility Commitment.

(4) Any available amount under the Dividend Credit Facility that NCN does not request a Dividend Credit Advance for by the date set out in Section 2.2(2) shall be a permanent reduction of the Dividend Credit Facility Commitment.

2.3 <u>Available Dividend Credit Advances.</u>

(1) Hydro shall, on the terms and conditions of this Agreement, make the Dividend Credit Advances available to NCN under the Dividend Credit Facility in accordance with Section 3.2.

(2) All Dividend Credit Advances requested hereunder shall be made available to NCN in accordance with Article III.

2.4 <u>Repayment on the Maturity Date.</u>

The Total Outstandings, if any, and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility shall become due and payable on the Maturity Date and subject to Hydro making an early demand for payment pursuant to Section 8.1 following an Event of Default, NCN shall repay on the Maturity Date, the Total Outstandings, if any, all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility. Notwithstanding the foregoing, if on the Maturity Date, NCN and TPC are not in default in respect of any material provision of the Loan Documents, the amount of the Total Outstandings and all accrued and unpaid interest thereon on the Maturity Date and all other amounts owing to Hydro under the Dividend Credit Facility will, subject to the right to prepay in accordance with the provisions of this Agreement, be repaid to Hydro solely through Hydro receiving all Distributions from time to time on TPC's Units. The Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility; second, in payment of all accrued and unpaid interest under the Dividend Credit Facility; and third, in repayment of all principal amounts under the Dividend Credit Facility. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro, as provided for under the Security Documents, until the Total Outstandings and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility have been repaid in full out of the said Distributions; provided however, that the payments to be made to Hydro pursuant to this Section 2.4 out of the Distributions on TPC's Units, shall be paid in the order of priority as set out in Section 3.7 of the TPC Financing Agreement, and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement or the Revenue Advance Consolidation Agreement, the non-payment of such Distributions to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

It is acknowledged that Hydro shall have no right to sue NCN on the personal covenant to pay the said amounts, nor to sue TPC on any personal covenant to pay the said amounts under the Guarantee; it being acknowledged that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Security Documents.

2.5 **Mandatory Repayments during the Term of this Agreement.**

(1) If, on any day, Hydro notifies NCN that the Total Outstandings exceeds the Dividend Credit Facility Commitment, (and commencing on the day after the twenty-fifth Anniversary Date, the Total Outstandings exceeds the lesser of the Dividend Credit Facility Commitment or the Dividend Credit Facility Commitment Cap) (such excess being referred to herein as the "**Over-Drawn Amount**"), NCN shall repay to Hydro, an amount sufficient to reduce the Total Outstandings by at least the Over-Drawn Amount. Notwithstanding the foregoing, provided that NCN and TPC are not in default in respect of any material provision of the Loan Documents, and subject always to the right to prepay as set out herein, the Over-Drawn Amount and all accrued and unpaid interest thereon and applicable costs and expenses, if any, will be repaid solely through the Distributions from time to time on TPC's Units pursuant to the provisions of the Security Documents. The Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility; second, in payment of all accrued and unpaid interest under the Dividend Credit Facility; and third, in repayment of all principal amounts under the Dividend Credit Facility. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for in the Security Documents until the Over-Drawn Amount and all costs and expenses and accrued and unpaid interest thereon has been repaid in full. The payments made to Hydro pursuant to this Section 2.5(1) out of the Distributions on TPC's Units shall be paid in the order of

priority as set out in Section 3.7 of the TPC Financing Agreement and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement in compliance with such priority provisions, the non-payment of such Distributions to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

(2) In addition to all other mandatory repayment obligations provided for in this Agreement and subject always to the right to prepay in accordance with the provisions of this Agreement, NCN shall throughout the term of this Agreement repay to Hydro the Total Outstandings plus all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility solely through Hydro receiving all Distributions on TPC's Units. Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above); second, in payment of all accrued and unpaid interest under the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above); and third, in repayment of all principal amounts under the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above). Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until all such amounts have been repaid in full. The amount of any repayment shall be a permanent reduction of the Dividend Credit Facility Commitment. The payments to be made to Hydro pursuant to this Section 2.5(2) out of Distributions on TPC's Units shall be paid in the order of priority as set out in Section 3.7 of the TPC Financing Agreement and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement or the Revenue Advance Consolidation Agreement in compliance with such priority provisions,

the non-payment of such Distributions to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

(3) It is acknowledged that Hydro shall have no right to sue NCN on the personal covenant to pay the said amounts, nor to sue TPC on any personal covenant to pay the said amounts under the Guarantee, it being acknowledged that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Security Documents.

2.6 <u>Optional Reductions.</u>

(1) Subject to Section 2.6(2), NCN may prepay, in whole or in part, the Total Outstandings, at any time, upon at least two (2) Business Days notice to Hydro (the "**Repayment Notice**"). Each Repayment Notice shall be in substantially the form of Schedule "A" and shall specify:

(a) the proposed date of such prepayment or reduction; and

(b) the aggregate principal amount of the prepayment or reduction, and, if such Repayment Notice is given, NCN shall:

(c) pay Hydro in accordance with such Repayment Notice the amount of prepayment; and

(d) pay Hydro all interest on the amount of such prepayment or excess amount accrued to the date of such prepayment.

(2) Each partial prepayment of Total Outstandings shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.

2.7 Evidence of Debt and Determination of Interest Rates and Fees.

(1) The indebtedness of NCN in respect of all Dividend Credit Advances hereunder shall be evidenced by the account records maintained by Hydro, which shall be *prima facie* evidence of such indebtedness for all purposes, absent error. Hydro shall indemnify and save harmless NCN for losses suffered or costs incurred by NCN due to Hydro's failure to correctly record or calculate any amount, rate, date or other data (including calculations by Hydro to determine any amount) in the account records or in statements or notices issued to NCN, where such failure was due to the gross negligence or willful misconduct of Hydro or any person for whom Hydro is responsible at law. Notwithstanding the foregoing, the failure of Hydro to correctly record or calculate any amount, rate, date or other data (including calculations to determine any amount) in the account records, or in statements or notices issued to the Limited Partnership hereunder shall not affect the obligation of NCN and TPC to pay amounts due hereunder to Hydro in the manner contemplated herein, and in accordance with the other Loan Documents.

(2) For purposes of the *Interest Act* (Canada):

(a) whenever any interest under this Agreement is calculated using a rate based on a period of time other than a calendar year, such rate determined pursuant to such calculation, when expressed as an annual rate, is equivalent to (x) the applicable rate based on such period of time multiplied by (y) the actual number of days in the calendar year in which the period for which such interest or fee is calculated ends, and divided by (z) the number of days in such period of time;

(b) the principle of deemed reinvestment of interest shall not apply to any interest calculation under this Agreement; and

(c) the rates of interest stipulated in this Agreement are intended to be nominal rates and not effective rates or yields.

(3) Within ten (10) Business Days of the last day of each month during this Agreement Hydro shall provide to NCN a written statement setting out the following information as at the last day of each month:

(a) the Total Outstandings under the Dividend Credit Facility, together with the following information:

(i) opening balances;

(ii) closing balances;

(iii) Dividend Credit Advances provided during the month;

(iv) principal repaid during the month, if applicable;

(v) interest paid by or on behalf of NCN, and applicable interest rate(s) charged to NCN during the month; and

(vi) any costs charged by Hydro to NCN during the month, and any reimbursements made by or on behalf of NCN to Hydro during the month for costs charged by Hydro to NCN.

ARTICLE III
DIVIDEND CREDIT ADVANCES

3.1 **<u>Dividend Credit Advances.</u>**

Hydro agrees, on the terms and conditions of this Agreement, to make Dividend Credit Advances to NCN under the Dividend Credit Facility, from time to time, on any Business Day.

3.2 Procedure for Borrowing.

Where NCN wishes to receive a Dividend Credit Advance under the Dividend Credit Facility, a notice (a "**Borrowing Notice**") shall be given by NCN to Hydro not later than 10:00 a.m. (Winnipeg time), at least two (2) Business Days but not more than five (5) Business Days prior to the date of the proposed Dividend Credit Advance, which Borrowing Notice shall be irrevocable and binding on NCN. Each Borrowing Notice shall be in substantially the form of Schedule B and shall specify:

(a) the requested date of the Dividend Credit Advance; and

(b) the aggregate amount of the Dividend Credit Advance.

Subject to the terms and conditions of this Agreement, Hydro shall forward the funds for the Dividend Credit Advance on the specified date for such Dividend Credit Advance in accordance with the Borrowing Notice forwarded to Hydro.

3.3 Interest on Dividend Credit Advances.

Each Dividend Credit Advance, or the amount thereof remaining outstanding from time to time, shall bear interest at the rate applicable to the Dividend Credit Advance determined in accordance with this Section 3.3 from the date the Dividend Credit Advance is first received in the account specified by NCN in the applicable Borrowing Notice to the date on which the Dividend Credit Advance is repaid in full or dealt with as otherwise specified in this Agreement. Each Dividend Credit Advance shall bear interest at a rate per annum equal at all times for that Dividend Credit Advance to the Canadian Ten Year Rate in effect on the date the said Dividend Credit Advance is first received in the account specified by NCN in the applicable Borrowing Notice. Interest on each of the Dividend Credit Advances made March 3, 2014, January 5, 2015 and on any date prior to November 1, 2015 shall be calculated monthly and compounded semi-annually from the date of advance to October 31, 2015. After November 1, 2015, if a Dividend Credit Advance is received in the account specified by NCN on a date other than November 1 of the year, interest on that Dividend Credit Advance shall accrue in the current month and be added to the Total Outstandings. Commencing November 1, 2015 and in each month thereafter Hydro shall calculate a blended interest rate based on the interest rates applicable to each Dividend Credit Advance, in proportion to the amount of each Dividend Credit Advance and the accrued interest thereon to that date, which rate shall be applied to all Dividend Credit Advances and all other amounts owing to Hydro under the Dividend Credit Facility on that date to October 31 of the following year. If there is no Dividend Credit Advance during a month, the blended rate for the month shall continue to apply. Such interest shall be calculated and compounded semi-annually and shall only become due and payable on the Maturity Date subject to the provisions of this Agreement (including payments made through Distributions under Article II, NCN's optional right of prepayment and action taken if an Event of Default occurs). Hydro shall provide NCN with notice of the Canadian Ten Year Rate applicable to each such Dividend Credit Advance and notice of the blended interest rate, together with its supporting calculation of the Canadian Ten Year Rate and the blended interest rate which will constitute, in the absence of error, *prima facie* evidence of the Canadian Ten Year Rate and the blended interest rate applicable to each such Dividend Credit Advance and all other amounts owing to Hydro under the Dividend Credit Facility.

3.4 TPC Financing Agreement.

Notwithstanding any other provision of this Agreement, it is acknowledged and agreed by the parties hereto that in the event that TPC sells all of TPC's Units to Hydro, whether pursuant to any Sale (as that term is defined in the TPC Financing Agreement), or otherwise, the Total Outstandings under the Dividend Credit Facility, all costs hereunder and all other amounts whatsoever owed by NCN to Hydro under this Agreement or any Loan Documents pursuant hereto (including the Guarantee) shall be deemed to have been paid in full and satisfied by the sale of TPC's Units to Hydro. NCN's right to receive Dividend Credit Advances will be suspended when Hydro receives notice that TPC is exercising its right to sell all of TPC's Units pursuant to the provisions of the TPC Financing Agreement or upon Hydro providing notice to

TPC that it is exercising its right to purchase all of TPC's Units pursuant to the provisions of the TPC Financing Agreement. The Dividend Credit Facility will terminate on the date that the sale of TPC's Units is completed in accordance with the provisions of the TPC Financing Agreement.

ARTICLE IV
CONDITIONS OF LENDING

4.1 <u>Conditions of All Dividend Credit Advances.</u>

At any time, the obligation of Hydro to make a Dividend Credit Advance shall be subject to the following conditions being satisfied on the date of such Dividend Credit Advance, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro, in its sole discretion:

(a) **Facility Limits**. The Total Outstandings shall not:

(i) prior to or after giving effect to the Dividend Credit Advance, exceed the Dividend Credit Facility Commitment; provided however that where a Dividend Credit Advance requested by NCN would cause the Total Outstandings to exceed the Dividend Credit Facility Commitment, Hydro shall make a Dividend Credit Advance equal to the amount that shall cause the Total Outstandings to equal, but not exceed, the Dividend Credit Facility Commitment; and

(ii) commencing on the day after the twenty-fifth Anniversary Date, the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility shall not, after giving effect to the Dividend Credit Facility Advance, exceed the Dividend Credit Facility Commitment Cap; provided however, that where a Dividend Credit Advance requested by NCN would cause the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility to exceed the Dividend Credit Facility Commitment Cap, Hydro shall make a Dividend Credit Advance equal to the amount that shall cause the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility, to equal, but not exceed, the Dividend Credit Facility Commitment Cap.

(b) **Truth of Representations and Warranties**. The representations and warranties of NCN and TPC contained in this Agreement and in any other Loan Documents to which each is a party, shall be true and correct as of the date on which any Dividend Credit Advance is made with the same force and effect as if such representations and warranties had been made on and as of such date; provided that, to the extent the disclosure in the representations and warranties is no longer true and correct, NCN and TPC shall be entitled to update such disclosure to Hydro, and if such disclosure is not materially adverse it must be approved by Hydro.

(c) **Performance of Covenants**. NCN and TPC shall have fulfilled or complied with all covenants herein contained (or contained in any other Loan Documents to which each is a party) to be performed by it at or prior to the date of such Dividend Credit Advance.

(d) **No Event of Default**. No Event of Default shall have occurred and be continuing.

(e) **Authorizations**. Hydro has obtained such borrowing authority (including the Additional Borrowing Authorizations) as may be required by it from time to time for the due and timely performance of its covenants under the Loan Documents, including in order to enable it to make the Advances requisitioned from time to time by NCN by Borrowing Notices.

(f) **No Change in Laws**. No Law or change in any Law shall have been enacted, the effect of which will be to prohibit Hydro from making any Dividend Credit Advance.

(g) **Borrowing Notice**. Hydro shall have received a Borrowing Notice in compliance with this Agreement.

ARTICLE V
REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties.

To induce Hydro to make Dividend Credit Advances available hereunder, NCN and TPC represent and warrant to Hydro that each of the following representations and warranties is true and correct:

(a) Status and Power.

(i) NCN is a "band" within the meaning of the Indian Act (Canada) and has the power to own or lease its personal property and its real property, other than the Reserve;

(ii) TPC is a corporation duly incorporated and organized and validly subsisting under the laws of Manitoba and has full corporate power and capacity to own its property and carry on its Business. TPC is duly qualified, licenced or registered to carry on business in Manitoba.

(b) Authorization.

(i) NCN has full power and capacity and full legal right to enter into and perform its obligation under this Agreement and the other Loan Documents to which it is or will be a party and has, or will have by the Initial Closing Date, taken all action necessary to be taken by it to authorize such acts;

(ii) TPC has full power and capacity and full legal right to enter into and perform its obligations under this Agreement and the other Loan Documents to which it is or will be a party and has or will have by the Initial Closing Date taken all action necessary to be taken by it to authorize such acts.

(c) Enforceability of Agreement.

(i) This Agreement and each other Loan Document to which NCN is a party constitutes legal, valid and binding obligations of NCN enforceable against it in accordance with their respective terms except as enforcement may be limited by the provisions of the Indian Act (Canada) and subject only to any limitation under applicable Laws relating to bankruptcy, insolvency, reorganization, moratorium or creditor's rights generally and the discretion that a court may exercise in the granting of equitable remedies;

(ii) this Agreement and each other Loan Document to which TPC is a party constitutes legal, valid and binding obligations of TPC enforceable against it in accordance with their respective terms, subject only to any limitation or applicable laws relating to bankruptcy, insolvency, reorganization, moratorium or creditor's rights generally and the discretion that a court may exercise in the granting of equitable remedies;

(d) Government Approval and Regulation. No authorization or approval or other action by, and no notice to or filing with, any Governmental Entity or other Person (other than those that have been, or by the Initial Closing Date will be, duly obtained or made) is required for the due execution, delivery or performance by NCN or TPC of any Loan Document to which NCN or TPC is a party.

(e) Litigation. There is no material action, suit or proceeding which has been commenced (Notice of which has been served on NCN or TPC), or to the best of the knowledge of NCN or TPC, is pending or threatened against NCN or TPC before or by any Governmental Entity, or before any arbitrator or board, which would prevent NCN or TPC from performing its obligations under any of the Loan Documents to which it is a party. NCN and TPC are not in default with respect to any judgment, order, writ, injunction, decree or award of any court, arbitrator, board or other Governmental Entity, nor is there any judgment, order, writ, injunction, decree or award which would prevent NCN or TPC from performing its obligations under any of the Loan Documents to which either is a party.

(f) Imposition of Lien. The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents to which it is a party by NCN will not result in or require the creation or imposition of any Lien on any Property of NCN except as otherwise permitted by this Agreement or the Loan Documents. The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents to which it is a party by TPC will not result in or require the creation or imposition of any Lien on the Property of TPC except as otherwise permitted by this Agreement or the Loan Documents.

(g) No Other Material Facts. None of:

(i) this Agreement;

(ii) any of the other Loan Documents; or

(iii) any certificate or statement in writing which has been supplied by or on behalf of NCN or TPC and is a document that is required to be delivered to Hydro pursuant to the provisions of this Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

(h) Restrictive Documents.

(i) NCN is not subject to, nor a party to any by-laws or resolutions of Chief and Council or of Members (or of any committees thereof, respectively), of NCN any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement and each of the other Loan Documents to which it is a party or compliance by NCN with the terms, conditions and provisions hereof or thereof;

(ii) TPC is not subject to or a party to, any restriction in its constating documents or by-laws, any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement and each of the other Loan Documents to which it is a party or compliance by TPC with the terms, conditions and provisions hereof or thereof or the continuing operation of the Business.

(i) Title to Collateral. TPC is the registered owner and sole beneficial owner of and has good and marketable beneficial title to and is lawfully possessed of its Property free and clear of all Liens, except Permitted Liens. A complete and accurate listing of its Property has been provided to Hydro, including the

Collateral, and TPC has full right to mortgage, pledge, charge and assign to Hydro the Collateral. No Person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding or commitment, for the purchase from NCN or TPC of the Collateral other than Hydro.

(j) Compliance with Laws. Each of NCN and TPC is in material compliance with all applicable Laws.

(k) No Breach of Contracts. Schedule C, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date, will contain a complete and accurate list of all agreements to which:

(i) NCN and/or TPC is a party in connection with the Corporate Distributions of TPC, the Capital Stock of TPC, the equity interest that NCN has in TPC, TPC's Units and Distributions on TPC's Units;

(ii) NCN is a party in connection with or arising out of the Wuskwatim Project creating liabilities or obligations upon any Person over the term of the agreement in excess of $75,000; and

(iii) TPC is a party creating liabilities or obligations upon any Person over the term of the agreements in excess of $75,000 or is otherwise material to TPC (collectively, the "**Material Agreements**"). NCN and TPC have provided copies of all Material Agreements, including amendments or additions thereto, to Hydro. On the date of the execution of each Future Material Agreement (as defined below in Section 6.1(11)), Schedule C shall be deemed to be amended to include such Future Material Agreements and such Future Material Agreements shall be deemed to be Material Agreements for the purposes of this Agreement from and after the date of execution without the necessity of any further action by any of the parties hereto. Each Material Agreement is in full force and effect, unamended (except as disclosed to Hydro), and there exists no default or event, occurrence, condition or act (including the completion of the transactions contemplated under this Agreement and any other Loan Document) which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a default thereunder. Neither NCN nor TPC have violated or breached, in any respect, any of the terms or conditions of any Material Agreement and, to the best of the knowledge of NCN and TPC, all the material covenants to be performed by any other party thereto have been fully performed in all material respects.

(l) Books and Records. All books and records of TPC have been fully, properly and accurately kept and completed in accordance with GAAP and there are no material inaccuracies or discrepancies of any kind contained or reflected therein.

(m) Tax Liability. Except for any Taxes which are being diligently contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books:

(i) TPC has in a timely manner filed all tax returns, elections, filings and reports with respect to Taxes required by Law to be filed by it and such returns, elections, filings and reports are true, complete and correct;

(ii) TPC has paid, or reserved in its financial statements, all Taxes which are due and payable, and has paid all assessments and reassessments and all other Taxes, governmental charges penalties, interest and fines due and payable by it;

(iii) TPC has no liability, contingent or otherwise, for Taxes, except Taxes not now due and payable with respect to ordinary operations during the current fiscal period adequate provision for the payment of which has been made; and

(iv) TPC has paid as and when due all applicable Taxes and remitted as required by Law all applicable Taxes and deductions and any interest or penalties related thereto.

(n) Shareholder. NCN is the beneficial owner of all of the Capital Stock of TPC free and clear of all Liens except Permitted Liens. The Capital Stock of TPC is owned by the Chief or a Councillor of NCN, as bare trustee for NCN. No Person has any written or oral agreement, option, understanding or commitment, or any right capable of becoming an agreement, option, understanding, commitment, or right for purchase of any of the Capital Stock of TPC or to receive payment based on the value of any such Capital Stock. The issued and outstanding Capital Stock and Debt (excluding Debt under this Agreement) of TPC and the registered beneficial holders of such Capital Stock and Debt (excluding Debt under this Agreement) will be as described in Schedule D, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date. Hydro acknowledges that the NCN Deed of Assignment shall not be deemed to be a breach of this representation.

(o) Liabilities. TPC does not have any liabilities, whether accrued, absolute, contingent or otherwise, of any kind or nature whatsoever, except as otherwise disclosed in Schedule E, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date or pursuant to the Loan Documents, and except as incurred after the date hereof in compliance with this Agreement and the Loan Documents.

(p) No Event of Default. No Event of Default has occurred, nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute and Event of Default under the Loan Documents. No default has occurred nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute a default under any one or more of the Material Agreements which could result in the acceleration of amounts owing by NCN or TPC under any such Material Agreements.

(q) Financial Information. The financial statements of TPC furnished to Hydro pursuant to this Agreement have been prepared in accordance with GAAP, consistently applied, and present fairly the financial position of TPC as at the dates thereof and the results of their operations for the periods then ended. All balance sheets, all statements of operations, shareholders' equity and cash flow and all other financial information of TPC furnished pursuant to Section 6.1(a)(1) have been and will for periods following the Initial Closing be prepared in accordance with GAAP consistently applied, and do or will present fairly the consolidated financial position of TPC thereby as at the dates thereof and the results of their operations for the periods then ended.

Each of the representations and warranties contained in this Section 5.1 shall be deemed to be continually repeated by NCN and TPC at the time of each Dividend Credit Advance.

5.2 Survival of Representations and Warranties.

All the representations and warranties of NCN and TPC contained in Section 5.1 shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Dividend Credit Facility has been terminated notwithstanding any investigation made at any time by or on behalf of Hydro.

5.3 Representations by Hydro.

To induce NCN and TPC to enter into this Agreement, Hydro represents and warrants to NCN and TPC that each of the following representations and warranties is true and correct:

(a) Hydro is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and each of the other Loan Documents to which it is a party and to perform its obligations this Agreement and the Loan Documents.

(b) This Agreement and the Loan Documents to which Hydro is a party have been duly authorized, executed and delivered by Hydro and are legal, valid and binding obligations of Hydro enforceable, against Hydro by NCN and TPC to the extent that NCN or TPC is a party thereto, in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or, by this Agreement, at the discretion of the Arbitrator.

(c) Subject only to obtaining the Authorizations described in Schedule H, the execution and delivery of this Agreement and each of the Loan Documents to which Hydro is a party and the consummation the transactions herein provided for by Hydro will not result in:

(i) the breach or violation of any other provisions of or constitute a default under or conflict with or cause the acceleration of any obligation of Hydro under:

(A) any contract to which Hydro is a party or by which it, or any of its property, is bound;

(B) any provision of the constating documents, by-laws or resolutions of the board of directors (or any committee thereof) of Hydro;

(D) any judgment, decree, order or award of any court, governmental body or arbitrator having jurisdiction over Hydro; or

(E) any applicable law, statue, ordinance, regulation or rule, including, without limitation, the *Hydro Act*; or

(ii) the creation or imposition of any Lien on any investment transaction or any of the property or assets of Hydro.

(d) Hydro is a resident of Canada for the purposes of the Income Tax Act (Canada).

(e) None of (i) this Agreement; (ii) any of the other Loan Documents; or (iii) any certificate or statement in writing which has been supplied by or on behalf of Hydro and is a document that is required to be delivered to Hydro pursuant to this Agreement or any of the other Loan Documents, contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

(f) There is no requirement for Hydro to make any filing with, give any notice to or obtain any license, permit, certificate, registration, authorization, consent or approval of any government regulatory authority as a condition to the lawful consummation by Hydro of the transaction contemplated by this Agreement and each other Loan Document to which it is a party, except as described in Schedule H.

Each of the representations and warranties contained in this Section 5.3 shall be deemed to be continually repeated by Hydro at the time of each Dividend Credit Advance.

5.4 Survival of Representations and Warranties.

All the representations and warranties of Hydro contained in Section 5.3 shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Dividend Credit Facility has been terminated, notwithstanding any investigation made at any time by or on behalf of NCN or TPC.

ARTICLE VI
COVENANTS OF NCN AND TPC

6.1 Affirmative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Dividend Credit Facility Commitment under this Agreement, and unless Hydro shall otherwise consent, NCN and TPC shall:

(a) Financial Reporting and Deliveries. Cause to be delivered to Hydro as soon as available, and in any event within one hundred and twenty (120) days after the end of each Financial Year, the audited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC for such Financial Year, prepared in accordance with GAAP and subject to an unqualified opinion of the Auditors;

(b) Additional Reporting and Deliveries. Cause to be delivered to Hydro, the following documents, in form and substance satisfactory to Hydro acting reasonably:

(i) a copy of each management letter or report submitted to the board of directors (or any committee thereof) or senior management of TPC by the Auditors in connection with any annual, interim or special audit made by them of the books of TPC, together with the related response of TPC to be delivered promptly upon the issuance of the response by TPC;

(ii) promptly after the occurrence of any Event of Default, a statement of NCN setting forth the details of such Event of Default and the action which NCN and/or TPC propose to take or have taken with respect thereto;

(iii) promptly after the commencement thereof, Notice of Claims which have been commenced against NCN or TPC (notice of which has been served on NCN or TPC), or to the best of the knowledge of NCN or TPC, are pending or threatened against NCN or TPC for amounts which exceed $75,000 in the aggregate at any time or affect any of the Collateral;

(iv) promptly after the occurrence of any material development with respect to any Claims referred to in Section 6.1(2)(c), and in any event within three (3) Business Days after NCN or TPC obtains knowledge of the occurrence thereof, Notice thereof to Hydro, and, to the extent Hydro requests them, copies of all documentation relating thereto; and

(v) such other information and reports relating to TPC, the Collateral or the Business or NCN's interest in TPC, as Hydro may from time to time reasonably request.

(c) Existence. Preserve and maintain TPC's corporate existence.

(d) Compliance with Laws. Comply, in all material respects with the requirements of all applicable Laws.

(e) Payment of Taxes, Claims and Governmental Licence Fees. Pay and discharge in respect of TPC, before the same shall become delinquent:

(i) all Taxes, governmental assessments, charges or levies and Claims imposed upon it or upon any of its Property;

(ii) all lawful Claims which, if unpaid, might by Law become a Lien upon its Property, in each case except for any such Tax, assessment, charge, levy or Claim which would result in a Lien which is a Permitted Lien; and

(iii) all fees payable to Governmental Entities or other authorities in connection with all governmental licences issued to and held by TPC (if any).

(f) Keeping of Books. Keep or cause to be kept, proper books, records and accounts, in which full and correct entries shall be made of all of TPC's financial transactions in accordance with GAAP.

(g) Visitation and Inspection. If, in the reasonable opinion of Hydro, an Event of Default has or may have occurred, at any reasonable time or times and upon reasonable prior notice given to NCN and TPC by Hydro, permit Hydro or any of its authorized representatives, full and reasonable access to the premises of NCN and TPC and obtain any consents and waivers from any Person necessary, in the reasonable opinion of Hydro to ensure such access, for the purposes of inspecting (and, where required, taking copies of) the respective business, financial and computer records of NCN (but relating to the Wuskwatim Project only) and TPC and to discuss the respective business, financial and computer records of NCN (but relating to the Wuskwatim Project only) and TPC, and compliance by NCN and TPC with the terms of this Agreement and the other Loan Documents (to the extent that each is a party thereto), with the management and Auditors thereof.

(h) Protect Hydro Liens. At all times take all action and supply Hydro with all such information necessary to allow Hydro to create, maintain, perfect, protect and preserve the Liens provided for under the Security Documents and confer upon Hydro the security interest intended to be created thereby.

(i) Payments. Pay all amounts of principal, interest, costs and expenses in the manner, on the dates, at the times and at the places specified in this Agreement or under any other Loan Document, but subject to the provisions of Section 8.2 in respect of costs and expenses.

(j) Payment of Preferred Claims. Pay, as and when due, any and all amounts which may result in a Lien on the Collateral under applicable Law (other than a Permitted Lien) whether or not such Lien is entitled to priority over the Liens in favour of Hydro under the Security Documents.

(k) Loan Documents. Execute and deliver to Hydro the Loan Documents.

(l) Material Agreements. Comply with the provisions of all of the Materials Agreements. In respect of each Material Agreement executed by NCN and/or TPC after the date hereof (each a "**Future Material Agreement**"), provide to Hydro, a certified copy of each Future Material Agreement.

(m) Notice of Defaults. Immediately notify Hydro:

(i) of any Event of Default or of any event, occurrence, condition or act which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become an Event of Default, or of any material default (either by NCN or TPC) under any Material Agreement or of any event which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a material default under or would otherwise allow the termination of any Material Agreement, and thereafter provide Hydro with all information reasonably requested by Hydro from time to time concerning the status thereof;

(ii) on becoming aware of the occurrence of any litigation, dispute, arbitration, proceeding, labour or industrial dispute the result of which if determined adversely would have a Material Adverse Business Effect on the ability of NCN and/or TPC to perform their respective obligations under this Agreement and the other Loan Documents and thereafter provide Hydro with all information reasonably requested by Hydro concerning the status thereof.

(n) Further Assurances. Upon request of Hydro, duly execute and deliver or cause to be duly executed and delivered to Hydro such further instruments and other documents, and do and cause to be done such further acts as may be necessary or desirable in the opinion of Hydro, acting reasonably, to carry out more effectively the provisions and purposes of the Loan Documents.

6.2 Negative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Dividend Credit Facility Commitment under this Agreement and unless Hydro, as the case may be, shall otherwise consent, NCN and TPC agree that:

(a) Business Activity. TPC shall not engage in any business activity except the Business.

(b) Liens. No Liens shall be created, incurred, assumed or suffered to exist, on any of TPC's Property including the Collateral and the Capital Stock of TPC other than Permitted Liens. For greater certainty this does not prohibit the NCN Deed of Assignment.

(c) Disposal of Property. None of the Collateral shall be disposed of by TPC.

(d) Debt. Except with the prior consent of Hydro, TPC shall not allow any Debt of TPC to be created, incurred, assumed or suffered to exist, directly, or contingently or otherwise, other than:

(i) Debt to Hydro;

(ii) unsecured current liabilities incurred and payable in the ordinary course of the Business and not represented by any note, bond or debenture; or

(iii) Purchase Money Debt, provided that the payments under such Purchase Money Debt does not exceed an aggregate amount in any one year period of $15,000.

(e) Mergers. TPC shall not reorganize, amalgamate, merge, consolidate or otherwise enter into any form of business combination with any other Person.

(f) Guarantees and Indemnities. TPC shall not guarantee or indemnify or give financial assistance or incur any contingent liability in respect of any Debt or any other obligations or liabilities of any other Person at any time other than pursuant to the Guarantee.

(g) Dividends. TPC shall not:

(i) declare or pay any dividends or any distributions after Hydro has provided notice to TPC that an Event of Default has occurred; nor

(ii) declare or pay any dividends or other distributions, in any other circumstances if, after declaring or paying such dividend or other distribution, TPC would not be able to meet its obligations under the Loan Documents.

(h) Financial Year and Auditors. TPC shall not change its Financial Year end or its Auditors.

(i) Change in Constating Documents or Capital Stock. There shall be no change in the constating documents or by-laws of TPC as delivered to Hydro which would amend the authorized shares or other equity securities of TPC or otherwise be detrimental to the rights or interests of Hydro under any of the Loan Documents or issue any Capital Stock in TPC that would cause an Event of Default to occur or would cause a Change of Control of TPC.

(j) Material Agreements. There shall be no amendment, supplement, termination or waiver, or entering into of any forbearance from exercising any rights with respect to, any of the terms of any Material Agreement in a manner which would cause a Material Adverse Business Effect or an Event of Default hereunder.

(k) Change of Control. There shall be no Change of Control.

(l) Change of Registered Owner. Change the registered owner of the Capital Stock of TPC to any person other than the Chief or a Councillor of NCN, as bare trustee for NCN, or change the form of bare trustee declaration prior to obtaining the written consent of Hydro to the change.

6.3 **Cross-Default.**

Any Event of Default (as defined in the TPC Financing Agreement) by TPC shall be deemed to be an Event of Default hereunder.

ARTICLE VII
SECURITY

7.1 Security.

Each of NCN and TPC shall execute and deliver, the Security Documents to which it is a party with each of the Security Documents to be in form and substance satisfactory to Hydro, acting reasonably, as and when required hereunder or under the Loan Documents as continuing collateral security in the Collateral for the due, prompt and complete payment, performance and satisfaction by TPC of all of NCN's indebtedness, liabilities and obligations of every nature whatsoever (whether present or future, direct or indirect, absolute or contingent, matured or unmatured, at any time due or accruing due, whatsoever and howsoever incurred, including any ultimate unpaid balance thereof, in any currency, and whether incurred prior to, at the time or subsequent to the execution of this Agreement) to Hydro, in connection with this Agreement and the other Loan Documents (collectively the "**Obligations**").

Notwithstanding anything to the contrary herein, this Agreement shall be interpreted in all respects having regard for the fact that, and the Security Documents shall provide that, (a) Hydro has a first charge security interest on TPC's Units and the Distributions on TPC's Units and any interest related to TPC's Units and the said Distributions, and (b) Hydro's sole recourse for payment of the Obligations shall be to the Collateral in accordance with the provisions of this Agreement, and for greater certainty, it shall have no right to sue TPC or NCN on any personal covenant to pay all or any of the Obligations, including without limitation, under the Guarantee.

7.2 Registrations.

Hydro, in its sole discretion, may register, file or record the Liens constituted by the Security Documents in all jurisdictions where such registration, filing, or recording is necessary or of advantage to the creation, perfection, preservation or protection of such Liens.

7.3 Renewals.

Hydro may renew such registrations, filings and recordings from time to time as and when required or of advantage, in the sole discretion of Hydro, to keep them in full force and effect. NCN and TPC acknowledge that the forms of the Security Documents have been prepared based upon the laws of the jurisdictions indicated therein as being applicable thereto in effect at the date hereof and that such Laws may change. NCN and TPC agree that, following prior notice to and consultation with NCN and TPC, upon direction from Hydro, Hydro shall have the right to require that the forms of the Security Documents be amended, restated or supplemented, to reflect any changes in such Laws, whether arising as a result of statutory amendments, court decisions or other similar changes, in order to confer upon Hydro the Liens in the Collateral intended to be created by the Security Documents, in the sole discretion of Hydro. For greater certainty, nothing in this Agreement can be used by Hydro, TPC or NCN or by any other Person to expand or reduce or otherwise change the scope of the Property comprising the Collateral herein defined or to confer upon Hydro a right to sue TPC or NCN on a personal covenant to pay all or any of the Obligations, or to require any guarantees (except the Guarantee), indemnities or covenants from NCN or any other Person in respect of the Obligations or otherwise.

ARTICLE VIII
EVENTS OF DEFAULT

8.1 Events of Default.

If any of the following events, conditions or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) NCN shall fail to pay any portion of the principal or interest or any fees or other amounts due hereunder or under any of the other Loan Documents on the date when due hereunder or thereunder and such amount remains unpaid for a period of six (6) Business Days after Hydro notifies NCN that the amount is overdue;

provided however, that this provision shall be read in conjunction with the provisions in this Agreement, the TPC Financing Agreement and the other Loan Documents hereunder and thereunder which provide that, for so long as TPC and NCN are otherwise in good standing under the provisions of this Agreement, the TPC Financing Agreement and the other Loan Documents hereunder and thereunder, all such payments to Hydro are to made solely through the irrevocable assignment and direction to Hydro of the Distributions on TPC's Units (or a portion thereof, as applicable under the priority provisions of the TPC Financing Agreement) prior to the Maturity Date (and, in certain circumstances, after the Maturity Date), and from no other source, such that for so long as the Distributions are so assigned by TPC (as collateral security for the Guarantee) and are paid over to Hydro as and when declared by the General Partner of the Limited Partnership pursuant to the irrevocable assignment and direction in favour of Hydro, NCN shall be deemed to be in compliance with its covenants to pay for all purposes hereunder and under the other Loan Documents. The parties hereto acknowledge that neither TPC nor NCN control the timing or amount of such Distributions, and as such, there may be periods of time during which there are no or few Distributions to be paid over to Hydro in accordance with the irrevocable assignment and direction to Hydro, and this shall not be construed to be an Event of Default hereunder;

(b) any representation or warranty or certification made or deemed to be made by any NCN or TPC or pursuant to or in connection with any of the Loan Documents delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(c) NCN or TPC shall fail to perform or observe any other term, covenant or agreement contained in any of the Loan Documents on its part to be performed or observed and such failure shall remain unremedied for fifteen (15) Business Days (the "**Cure Period**") after written notice thereof shall have been given to NCN and TPC by Hydro; provided that the length of the Cure Period shall be extended by Hydro in its unfettered discretion where NCN and TPC demonstrate to Hydro that the breach is not capable of being cured within fifteen (15) Business Days but provides Hydro, within fifteen (15) Business Days, with a plan for curing the breach within sixty (60) calendar days and in good faith implements such plan;

(d) any of the Loan Documents, at any time, is not or ceases to be valid or enforceable in whole or in part, or if any Lien intended to be created by any of the Security Documents is not or ceases to be a valid and perfected Lien having the ranking or priority contemplated thereby, or if the validity or enforceability of any of the Loan Documents or the validity or perfection of any such Lien shall be contested by any party thereto or any other Person (unless such contestation by such party or other Person is being opposed diligently, in good faith and by proper legal proceedings by Hydro with the assistance of NCN and TPC and Hydro covenants to oppose such contestation in good faith, where in its discretion, there is a reasonable prospect of success), or if any Person (other than Hydro or the Limited Partnership) obtains any interest in the Collateral or any part thereof (except Permitted Liens); provided however, that this provision shall only be invoked where Hydro, acting reasonably, has determined that its inability to enforce the said Lien with its intended ranking or priority cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected notwithstanding that NCN and TPC have provided a written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said Lien with its intended ranking or priority;

(e) with respect to Debt of TPC under any one or more agreements other than the Debt under the Loan Documents,

(i) TPC shall fail to pay any principal, interest or other amount pursuant to the agreements governing such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) when such amount becomes due and payable (whether by scheduled maturity, required repayment, acceleration, demand or otherwise) and such failure shall continue after any applicable grace period specified in such agreement or agreements; or

(ii) any other event, condition or circumstance shall occur and shall continue after any applicable grace period specified in such agreement or agreements, if the effect of such event, condition or circumstance is to accelerate the maturity of such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency); or

(iii) other Debt of TPC in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) shall be declared to be due and payable prior to the stated maturity thereof under any such agreement or agreements;

(f) the occurrence of any default, or any event or condition which, with the giving of notice or passage of time, or both would constitute a default under any Material Agreement and such default shall continue unremedied after any applicable grace period specified in such Material Agreement;

(g) NCN or TPC shall:

(i) become insolvent;

(ii) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(iii) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iv) institute or have instituted against it any proceeding seeking (x) to adjudicate it a bankrupt or insolvent, (y) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors, or (z) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property, and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within forty five (45) days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; provided however, that in the event that a third party manager or co-manager is appointed for NCN, this shall not constitute an Event of Default hereunder provided that the third party manager or co-manager abides by the terms and conditions of this Agreement; or

(v) take any corporate action to authorize any of the foregoing actions;

(h) a Notice is sent to NCN or TPC from any creditor with respect to the intention of such creditor to enforce a Lien on:

(i) any of the Collateral; or

(ii) any Property of TPC (other than the Collateral) unless such Notice is being contested in good faith by appropriate legal proceedings and such Notice has not resulted in, or does not involve, any immediate danger of the sale, forfeiture or loss of any of the Property of TPC that is the subject of such Notice; or

(iii) the Capital Stock of TPC;

(i) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Entity which may be reasonably likely to require TPC to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against TPC, and either:

(i) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

(ii) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(j) the audited financial statements of TPC in respect of any Financial Year are qualified in any material adverse respect by the Auditors;

(k) the occurrence of a Change of Control;

(l) the loss, suspension or failure to renew any licence or permit held by TPC or any agreement to which TPC is a party the effect of which would prohibit or otherwise restrict TPC from conducting the Business;

(m) TPC is enjoined or restrained in any material way by an order of any Governmental Entity, arbitrator or board in Canada or elsewhere from conducting the Business;

(n) the occurrence of a Material Adverse Business Effect;

(o) the occurrence an Event of Default committed by TPC (as such term is defined in the TPC Financing Agreement); or

(p) the occurrence of any event, condition or circumstance which, with the giving of notice or passage of time or both, would constitute an Event of Default, after the expiration of, in the case of a Loan Document, the applicable Cure Period or in the case of any other agreement, the applicable cure period (if any) thereunder;

then, and in any such event, Hydro shall be entitled by written notice to NCN and TPC to: (i)terminate the obligation of Hydro to make further Dividend Credit Advances under the Dividend Credit Facility; and/or (ii) demand repayment of the Total Outstandings owed by NCN to Hydro under the Dividend Credit Facility, whereupon the Total Outstandings and other amounts payable thereunder shall become forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by NCN and TPC except such notices as may be required under applicable Laws. Provided, however that Hydro shall only have recourse to the Collateral for repayment of the Obligations and further provided, however, that upon any Event of Default specified in Section 8.1(g), the obligation of Hydro to make Dividend Credit Advances hereunder shall automatically terminate.

8.2 **Expenses of Hydro.**

Upon the occurrence of any Event of Default which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Default. All reasonable expenses, costs and charges incurred by or on behalf of Hydro in connection with:

(a) any remedial action taken pursuant to this Section; or

(b) the realization of the Collateral, including all reasonable fees, court costs, receiver's or agent's remuneration and other expenses of taking possession of, repairing, protecting, insuring, preparing for disposition, realizing, collecting, selling, transferring, delivering or obtaining payment of the Collateral, in all cases shall be added to and form a part of the Obligations, but subject always to the provisions that Hydro's sole recourse for payment of the Obligations shall be to the Collateral, as set out herein. For greater certainty, for so long as there is no Event of Default hereunder, Section 5.14 of the PDA shall govern the payment of Hydro's costs and expenses properly recoverable hereunder.

8.3 Remedies Cumulative.

The remedies provided for in this Agreement and each of the Loan Documents are cumulative and do not exclude any other right or remedy provided by Law (except that there shall be no right of Hydro to sue TPC or NCN on any personal covenant to pay, it being acknowledged that Hydro's sole recourse is to the Collateral).

8.4 Allocations.

For greater certainty, the parties agree that any expenses or costs that are, by the terms of this Agreement or under the other Loan Documents, reimbursable to Hydro shall be allocated to the Dividend Credit Facility.

ARTICLE IX

PAYMENTS, COMPUTATIONS AND INDEMNITIES

9.1 Timing of Payments under this Agreement.

Unless otherwise expressly provided in this Agreement:

(a) NCN shall make any payment required to be made by it to Hydro by depositing the amount of such payment in Hydro's Account not later than 11:00 a.m. (Winnipeg time) on the date such payment is due; and

(b) Hydro shall make any Dividend Credit Advance or other payment to NCN under this Agreement by crediting or causing the crediting of the account of NCN directed by NCN in the applicable Borrowing Notice with the amount of such Dividend Credit Advance on the date such Dividend Credit Advance is to be made.

9.2 Payments on Non-Business Days.

Whenever any payment hereunder shall be stated to be due on a day other than a Business Day, such payment shall be made on the next succeeding Business Day, and such extension of time shall not be included in the computation of interest unless an Event of Default has occurred and is continuing, in which event such extension of time shall be included in the computation of interest.

9.3 Overdue Amounts.

All amounts owed by NCN which are not paid when due (whether at stated maturity, on demand, by acceleration or otherwise) shall bear interest (both before and after judgment), from the date on which such amount is due until such amount is paid in full, payable on demand, at a rate per annum equal at all times, to the applicable rate specified in Section 3.3.

9.4 Application of Payments, Repayments and Prepayments.

All amounts received by Hydro from or on behalf of NCN, including a realization of the Collateral, and not previously applied pursuant to this Agreement shall be applied:

(a) first, in reduction of NCN's obligation to pay any costs or expenses which are due and owing to Hydro, and reimbursable or indemnity amounts or Losses which have been determined by a court of competent jurisdiction or by arbitration to be due and owing to Hydro;

(b) second, in reduction of NCN's obligation to pay any unpaid interest accrued on the principal amount of Dividend Credit Advances;

(c) third, in reduction of such NCN's obligation to pay any amounts due and owing on account of the principal amount of all Dividend Credit Advances;

(d) fourth, to be held in escrow by Hydro in an interest-bearing account on account, and up to the amount, of any written claim by Hydro then issued and outstanding seeking reimbursement or indemnity hereunder for Losses, pending determination by a court of competent jurisdiction or by arbitration as to the amount (if any) which is due and owing to Hydro hereunder (in which event, such funds and any interest earned thereon shall be dealt with in accordance with the order of the court of competent jurisdiction or arbitrator, as the case may be); and

(e) fifth, to NCN or such other Persons as may lawfully be entitled to the remainder, or as any court of competent jurisdiction may otherwise direct.

9.5 **Computations of Interest and Fees.**

(a) All computations of interest shall be made by Hydro, based on the semi-annual interest computation (and not the number of days in the six (6) month period) and on the basis of a year of 365 days.

(b) Notwithstanding any provision to the contrary contained in this Agreement, in no event shall the aggregate "interest" (as defined in Section 347 of the *Criminal Code* (Canada), as the same may be amended, replaced or re-enacted from time to time) payable under this Agreement exceed the maximum amount of interest on the "credit advanced" (as defined in that Section) under this Agreement lawfully permitted under that Section and, if any payment, collection or demand pursuant to this Agreement in respect of "interest" (as defined in that Section) is determined to be contrary to the provisions of that Section, such payment, collection or demand shall be refunded to NCN. For purposes of this Agreement, the effective annual rate of interest shall be determined in accordance with generally accepted actuarial practices and principles over the term that the relevant Dividend Credit Advance is outstanding on the basis of annual compounding of the lawfully permitted rate of interest and, in the event of any dispute, a certificate of a Fellow of the Canadian Institute of Actuaries appointed by Hydro will be conclusive for the purposes of such determination.

(c) Each determination by Hydro of any amount payable hereunder by NCN shall be *prima facie* evidence of the amount payable for all purposes absent error.

9.6 **Indemnity for Change in Circumstances.**

(a) If any change in Law, or any change in the interpretation or application by any Governmental Entity of any Law occurring or becoming effective after the date of this Agreement or any compliance by Hydro with any direction or requirement having the force of Law) of any Governmental Entity made or becoming effective after the date of this Agreement, causes Loss to Hydro by:

(i) increasing the actual cost to Hydro of performing its obligations under this Agreement or in respect of any Dividend Advance;

(ii) reducing any amount otherwise properly payable to Hydro under this Agreement or in respect of any Dividend Advance by any amount that Hydro deems material acting reasonably (other than pursuant to Section 9.5(2));

then Hydro may give notice to NCN specifying the nature of the event giving rise to such Loss and NCN shall, within twenty (20) Business Days of demand, pay such amounts as Hydro may specify is necessary to compensate Hydro for such Loss. A certificate as to the amount of any such Loss, submitted in good faith by Hydro to NCN shall be *prima facie* evidence of the amount of such Loss for all purposes, absent error.

(b) Except as required by applicable Law, NCN and TPC shall make all payments under this Agreement to Hydro without deducting or withholding of any Taxes. To the extent that deduction or withholding of Taxes is required by applicable Law, NCN and TPC will:

(i) immediately notify Hydro of such requirement;

(ii) pay to the appropriate authority the full amount required to be so withheld or deducted before penalties attach thereto or interest accrues thereon;

(iii) promptly forward to Hydro an official receipt or other documentation reasonably satisfactory to Hydro evidencing such payment to such authority; and

(iv) pay to Hydro an additional amount so that Hydro receives the full amount it would have received had no such deduction or withholding been required.

If any Taxes are directly asserted against Hydro with respect to any payment under this Agreement, Hydro may pay such Taxes and NCN shall promptly pay such additional amount (including any penalties, interest and expenses) necessary so that the net amount received by Hydro after the payment of such Taxes, including any Taxes on such additional amounts, shall equal the amount Hydro would have received had Hydro not paid such Taxes.

NCN will indemnify Hydro for all incremental Taxes, interest or penalties that Hydro must pay if NCN fail to deduct or withhold any Taxes when due or to send Hydro the required receipts or other documentation.

Hydro acknowledges that in respect of this Section 9.6(b), Taxes shall not include any income taxes that may be payable by Hydro. Hydro shall remain solely obligated to pay and shall save TPC and NCN harmless from any income taxes that may be asserted against Hydro or payable by Hydro, including with respect to any payments or amounts received or made under this Agreement.

9.7 Indemnity.

(a) NCN hereby agrees to indemnify, exonerate and hold Hydro and its officers, directors, employees, agents and other representatives (in this Section 9.7(1), the "**Indemnified Parties**") free and harmless from and against any and all Claims, demands, actions, causes of action, suits, losses, costs (including all documentary, recording, filing, mortgage duties), charges, liabilities and damages, and expenses in connection therewith (irrespective of whether such Indemnified Party is a party to the action for which such indemnification hereunder is sought), and including reasonable legal fees and disbursements (collectively, in this Section 9.7(1), the "**Indemnified Liabilities**") paid, incurred or suffered by, or asserted against, the Indemnified Parties or any of them or, with respect to, or as a direct or indirect result of:

(i) any transaction financed or to be financed in whole or in part, directly or indirectly, with the proceeds of any Dividend Credit Advances obtained hereunder; or

(ii) the execution, delivery, performance or enforcement of this Agreement or any Loan Documents, except for such Indemnified Liabilities that a court of competent jurisdiction determines or rules to be on account of the relevant gross negligence or willful misconduct of the Indemnified Party or any Person for whom such Indemnified Party is responsible at law [in which event, such Party shall indemnify TPC and its officers and directors and NCN and its Chief and Councillors (to the extent that each of NCN's Chiefs and Councillors is liable at law in his or her respective capacity as part of Chief and Council) for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct].

(b) All obligations provided for in this Section 9.7 shall not be reduced or impaired by any investigation made by or on behalf of Hydro.

(c) If, for any reason, the obligations of NCN pursuant to this Section 9.7 shall be unenforceable, NCN agrees to make the maximum contribution to the payment and satisfaction of each obligation that is permissible under Law, except to the extent that a court of competent jurisdiction determines such obligations arose on account of the gross negligence or willful misconduct or any Person for whom such Indemnified Party is responsible at law [in such event such Party shall indemnify TPC and its officers and directors and NCN and its Chief and Councillors (to the extent that each of NCN's Chiefs and Councillors is liable at law in his or her respective capacity as part of Chief and Council), for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct].

9.8 Contribution.

If any provision in any of the Loan Documents providing for indemnification by NCN (the "**Indemnitor**") in favour of Hydro or any of the Indemnified Parties (as defined in Section 9.7) (the "**Indemnitee**") is found by reason of the occurrence of an event, other than the gross negligence or wilful misconduct of the Indemnitee, to be unenforceable by a court of competent jurisdiction in a final judgment that has become non-appealable, then the Indemnitor shall contribute to the amount paid or payable by the Indemnitee which is subject to the indemnification provision in such proportion as is appropriate to reflect not only the relative benefits received by the Indemnitor on the one hand and the Indemnitee on the other hand but also the relative fault of the Indemnitor and the Indemnitee but only to the extent that such contribution is consistent with the terms of the final judgment. The rights of contribution herein provided shall be in addition to and not in derogation of any other right to contribution which the Indemnitee may have under this Agreement or applicable Laws.

9.9 Confirmation of Limited Recourse.

For greater certainty, Hydro acknowledges that nothing in this Article IX shall in any way detract from the limited recourse of Hydro's security and remedies hereunder, as set out in Section 7.1.

ARTICLE X
DISPUTE RESOLUTION

10.1 Dispute Resolution.

Each of the parties to the Agreement agrees that any disputes or claims arising out of this Agreement shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the PDA and it shall not bring any action in respect of any matter arising hereunder, other than pursuant to Article XXI of the PDA, against any other party.

ARTICLE XI
GENERAL PROVISIONS

11.1 Notices.

All notices provided for in this Agreement or in the other Loan Documents shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule F hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

Each Borrowing Notice and Repayment Notice shall be irrevocable and binding on NCN.

11.2 Time of the Essence.

Time shall be of the essence of this Agreement.

11.3 Third Party Beneficiaries.

Each party hereto intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any Person, other than the parties hereto and the Persons contemplated in Section 9.7 or Section 11.7, and no Person, other than the parties hereto and the Persons contemplated in Section 9.7 or Section 11.7, shall be entitled to rely on the provisions hereof in any action, suit, proceeding, hearing or other forum. For greater certainty, nothing in this Section 11.3 is intended to prevent or restrict the Taskinigahp Trust from receiving Dividends declared by the Board of Directors of TPC pursuant to the NCN Deed of Assignment subject always to TPC's compliance with the covenants, representations and warranties of this Agreement.

11.4 Enurement.

This Agreement shall enure to the benefit of and be binding upon the parties hereto. This Agreement shall be binding upon any assigns and enure to the benefit of any permitted assigns.

11.5 Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

11.6 Knowledge.

Where any representation or warranty contained in this Agreement or any other Loan Document is expressly qualified by reference to the "best of the knowledge" of NCN or TPC, or where any other reference is made herein or in any Loan Document to "the knowledge" of NCN or TPC, it shall be deemed to refer to the best of the knowledge of the Chief and Council of NCN and the members of the board of directors of TPC, respectively.

11.7 Assignment.

Neither this Agreement nor the rights and obligations hereunder shall be assignable or transferable by NCN or TPC or Hydro, except that Hydro may assign this Agreement to any Affiliate, on the condition that notwithstanding the Assignment, Hydro will remain jointly and severally liable with the said Affiliate, for compliance with the covenants of Hydro under this Agreement.

11.8 Non-Merger.

Except as otherwise expressly provided in this Agreement, the covenants, representations and warranties of the parties contained in this Agreement and the other Loan Documents shall not merge on and shall survive the Initial Closing and Final Investment Closing and the making of any Dividend Credit Advance, and notwithstanding such Initial Closing and Final Investment Closing or Dividend Credit Advance, or any investigation made by or on behalf of any party, shall continue in full force and effect. Neither the Initial Closing and Final Investment Closing nor the making of any Dividend Credit Advance shall prejudice any right of one party against any other party in respect of anything done or omitted hereunder or under any of the other Loan Documents or in respect of any right to damages or other remedies.

[Execution pages follow]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed on the date first above written.

NISICHAWAYASIHK CREE NATION

____
Marcel Moody, Chief

____
Ron Spence, Deputy Chief

____
Patrick Linklater, Councillor

____
Shirley L. Linklater, Councillor

____
Bonnie Linklater, Councillor

____
Willie Moore, Councillor

TASKINIGAHP POWER CORPORATION

Per: ______________________________
Name:
Title: President

Per: ______________________________
Name:
Title: Vice-President

Per: ______________________________
Name: Shirley L. Linklater
Title: Secretary-Treasurer

THE MANITOBA HYDRO-ELECTRIC BOARD

Per: ______________________________
Name:
Title: President and Chief Executive Officer

Per:
____
Name:
Title: Assistant Corporate Secretary

SCHEDULE A

REPAYMENT NOTICE

TO: THE MANITOBA HYDRO-ELECTRIC BOARD ("Hydro")

FROM: NISICHAWAYASIHK CREE NATION ("NCN")

This Repayment Notice is delivered to you pursuant to Section 2.6 of the financing agreement (the "Amended and Restated NCN Financing Agreement") dated Effective April 1, 2015 between NCN, as borrower, Taskinigahp Power Corporation and Hydro, as lender. All capitalized terms used in this Repayment Notice and defined in the NCN Financing Agreement shall have the meanings defined in the NCN Financing Agreement.

1. NCN hereby gives notice of repayment as follows:

   (a) Date of repayment:______________________________

   (b) Type of Advance:______________________________

   (c) Amount of principal being repaid:______________________________

NISICHAWAYASIHK CREE NATION

____
Chief

____
Councillor

____
Councillor

____
Councillor

____
Councillor

____
Councillor

SCHEDULE B

BORROWING NOTICE

To: THE MANITOBA HYDRO-ELECTRIC BOARD ("Hydro")

From: NISICHAWAYASIHK CREE NATION ("NCN")
TASKINIGAHP POWER CORPORATION ("TPC")

This Borrowing Notice is delivered to you pursuant to Section 3.2 of the amended and restated financing agreement (the "NCN Financing Agreement") dated as of April 1, 2015 between NCN, as borrower, TPC and Hydro, as lender. All capitalized terms used in this Borrowing Notice and defined in the NCN Financing Agreement shall have the meaning defined in the NCN Financing Agreement.

1. NCN hereby requests an Dividend Credit Advance as follows:

   (a) Date of Dividend Credit Advance:______________________________

   (b) Amount of Dividend Credit Advance:___________________________

   (c) Payment Instructions:____

2. NCN and TPC hereby certify that:

   (a) All of the representations and warranties of NCN and TPC contained in Section 5.1 of the NCN Financing Agreement are true and correct in all material respects on and as of the date hereof as though made on and as of the date hereof (other than those representations and warranties in Section 5.1 which are specifically limited to a particular date) and except as disclosed in writing to, and accepted in writing by Hydro.

   (b) All of the covenants of NCN and TPC contained in Article VI of the NCN Financing Agreement together with all of the conditions precedent to an Advance in Article IV of the NCN Financing Agreement (to the extent they are within NCN's and/or TPC's control) have been complied with or met in all material respects, except as disclosed in writing to, and accepted in writing by Hydro.

(c) No Event of Default has occurred and is continuing on the date hereof nor will any Event of Default occur as a result of the aforementioned Dividend Credit Advance, except as disclosed in writing to, and accepted in writing by Hydro.

DATED:

NISICHAWAYASIHK CREE NATION

____
Chief

____
Councillor

____
Councillor

____
Councillor

____
Councillor

____
Councillor

TASKINIGAHP POWER CORPORATION

Per:______________________________
Name:
Title:

Per:______________________________
Name:
Title:

SCHEDULE C

MATERIAL AGREEMENTS

Provided on Initial Closing

SCHEDULE D

ISSUED AND OUTSTANDING CAPITAL STOCK AND DEBT

Provided on Initial Closing

SCHEDULE E

LIABILITIES

Provided on Initial Closing

SCHEDULE F

ADDRESS FOR NOTICE

Nisichawayasihk Cree Nation
Attention: Chief and Council
General Delivery
Nelson House, MB
R0B 1A0

Fax Number: (204) 484-2392

Taskinigahp Power Corporation
Attention: President
General Delivery
Nelson House, MB
R0B 1A0

Fax Number: (204) 484-2392

Manitoba Hydro
Attention: General Counsel
360 Portage AvenueWinnipeg, MB

Fax Number: (204) 360-4947

SCHEDULE G

LIST OF SECURITY DOCUMENTS

1. TPC Limited Recourse Guarantee
2. TPC Security Agreement
3. Pledge of TPC's Units
4. Limited Power of Attorney granted by TPC respecting TPC's Units

SCHEDULE H

AUTHORIZATIONS - HYDRO

1. Order in Council as required pursuant to the provisions of the Hydro Act.
2. Such Additional Borrowing Authorizations required from time to time.

SCHEDULE 7.1
AMENDED AND RESTATED TPC FINANCING AGREEMENT

AMENDED AND RESTATED TPC FINANCING AGREEMENT

between

TASKINIGAHP POWER CORPORATION

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD

Effective March 31, 2015

TABLE OF CONTENTS

AMENDED AND RESTATED TPC FINANCING AGREEMENT

Effective the 31st day of March 2015

B E T W E E N:

TASKINIGAHP POWER CORPORATION,

(hereinafter referred to as "TPC")

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter referred to as "Hydro")

The parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement, defined terms used herein shall have the following meanings:

"**Advances**" means advances made by Hydro under the Equity Credit Facility in this Agreement in Canadian Dollars and "**Advance**" means any one of such Advances.

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person.

"**Aggregate Capital Contributions**" means for any particular day, the sum of: (i) the subscription price paid for the purchase of the Units by the Limited Partners; and (ii) all other capital amounts contributed by the Limited Partners to the Limited Partnership pursuant to the provisions of the Limited Partnership Agreement.

"**Agreement**" means this financing agreement and all schedules and instruments in amendment or confirmation of it; "**hereof**", "**hereto**" and "**hereunder**" and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; "**Article**", "**Section**" or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement.

"**Anniversary Date**" means each anniversary of the Final Closing Date.

"**Approved Funds**" means either: (i) funds that TPC will use to repay any principal amount under the Equity Credit Facility, that Hydro has approved pursuant to the Credit Facility Repayment Certification provided by TPC in accordance with Section 4.5; or (ii) funds that TPC will use to make a payment to the Limited Partnership, that Hydro has approved pursuant to the Limited Partnership Payment Certification.

"**Auditors**" means such firm of chartered accountants as may be selected by the directors of TPC and approved by NCN from time to time to audit TPC, provided that such firm of chartered accountants is qualified to perform audits in Manitoba.

"**Authorization**" means, with respect to any Person, any authorization, order, permit, approval, grant, licence, consent, right, franchise, privilege, certificate, judgment, writ, injunction, award, determination, direction, decree, by-law, rule or regulation of any Governmental Entity having jurisdiction over such Person, whether or not having the force of Law.

"**Banker's Acceptance Rate**" means the closing rate on any particular day for a one month Canadian Dollar banker's acceptance, as traced in Bloomberg using the CDOR01 index. Where any Banker's Acceptance Rate or average of a number of Banker's Acceptance Rates is used in the calculation of any interest rate or amount due by TPC hereunder (including in the determination of the Canadian Dollar Floating Rate), Hydro shall provide TPC with a print-out of the CDOR01 index screen used to derive such rate or rates.

"**Borrowing**" means a borrowing consisting of one or more Advances.

"**Business**" means the business of TPC which consists of owning TPC's Units, being a limited partner in the Limited Partnership and making such other investment, administrative and business decisions as may be ancillary thereto and carrying out such functions and fulfilling such obligations as are required or permitted pursuant to the provisions of the PDA.

"**Business Day**" means any day on which Hydro's head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba.

"**Canada**" means the Government of Canada.

"**Canada Yield Price**" means with respect to the repayment of Equity Credit Advances the principal amount that is being repaid plus or minus an amount calculated at 10:00 a.m. (Winnipeg time) on the Business Day preceding the day on which the principal amount is to be repaid which in total if invested on that day would provide a yield to maturity equal to the Government of Canada Yield, plus the Canadian Yield Spread, excluding commissions plus the Canadian Dollar Guarantee Rate. The Canada Yield Price will be determined based on the median of the three investment dealer quotes obtained by Hydro.

"**Canadian Dollar Floating Rate**" means, for any particular day(s) within a given month, the variable rate of interest (expressed as a percentage rate per annum) equal to the Short-Term Canadian Borrowing Cost incurred by Hydro for the month in which such day(s) fall. Provided that if there has been no Short-Term Canadian Borrowing Cost for that month, the variable interest rate (expressed as a percentage rate per annum) shall be based on the average of the daily Banker's Acceptance Rates for that month plus the average of the daily Canadian Dollar Guarantee Rates for that month plus one (1%) percent per annum.

"**Canadian Dollar Guarantee Rate**" means for any particular day, the closing rate of interest (expressed as a percentage rate per annum) charged on such day by Manitoba to Hydro, as a fee for Manitoba's guarantee of Hydro's Canadian Dollar borrowings.

"**Canadian Dollars**" and "**$**" each mean lawful money of Canada.

"**Canadian Yield Spread**" means for any particular date, the difference between the Government of Canada Yield determined for that date and the yield to maturity on such day compounded semi-annually which a non-callable Manitoba bond would carry if issued in Canadian Dollars on that day at 10:00 a.m. (Winnipeg time), including commission costs, at 100% of its principal amount on such day with the term to maturity equal to the remaining term to Maturity for the Equity Credit Advances that are being repaid. The Canadian Yield Spread will be determined by Hydro obtaining three rate quotes from investment dealers and using the median of the three rate quotes obtained.

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interest in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights, warrants or options to subscribe for or acquire an equity interest in such Person.

"**Change of Control**" means any change which results in NCN no longer directly owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of the bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC, as bare trustee for NCN, commits to vote such Capital Stock in accordance with the direction of Chief and Council of NCN), and for greater certainty the NCN Deed of Assignment does not effect a Change of Control.

"**Chief**" has the meaning ascribed thereto in the PDA.

"**Chief and Council**" has the meaning ascribed thereto in the PDA.

"**Claim**" means any claim of any nature whatsoever, including any demand, dispute, liability, obligation, debt, action, cause of action, suit, proceeding, litigation, arbitration, judgment, order, award, assessment and reassessment.

"**Collateral**" means TPC's Units and the Distributions thereon, in respect of which Hydro has or will have or is intended to have a Lien pursuant to the Security Documents.

"**Corporate Distributions**" means, in respect of any Person, whether or not a corporation, any form of distribution of its profits, including in each case any:

(i) declaration or payment of any dividend on its Capital Stock; and

(ii) payment to purchase, redeem, retire or acquire or reduce the stated capital of any of its Capital Stock, or any option, warrant or other right to acquire any such Capital Stock, or apply or set apart any of its Property therefore.

"**Councillor**" has the meaning ascribed thereto in the PDA.

"**Credit Facility Repayment Certification**" has the meaning specified in Section 4.5.

"**Cure Period**" has the meaning specified in Section 12.1(c).

"**Date of the PDA**" has the meaning ascribed thereto in the PDA.

"**Debt**" of any Person means, without duplication:

(i) all obligations of such Person for borrowed money or Advances and all obligations of such Person evidenced by bonds, debentures, notes or similar instruments;

(ii) all obligations of such Person, contingent or otherwise, relative to the face amount of all letters of credit, whether or not drawn, and banker's acceptances issued for the account of such Person; and

(iii) all other items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of such Person as of the date at which Debt is to be determined (excluding trade payables incurred in the ordinary course of business).

"**Distributions**" means distributions of cash of the Limited Partnership to TPC and the return of any part of the Aggregate Capital Contributions by the Limited Partnership to TPC.

"**Dividends**" has the meaning ascribed thereto in the NCN Deed of Assignment.

"**Dividend Credit Facility**" has the meaning ascribed thereto in the NCN Financing Agreement.

"**Equity Credit Advance**" means an Advance denominated in Canadian Dollars under the Equity Credit Facility.

"**Equity Credit Facility**" means the non-revolving credit facility to be made available to TPC by Hydro in the maximum amount of the Equity Credit Facility Commitment and in accordance with the terms of this Agreement.

"**Equity Credit Facility Commitment**" means the aggregate principal amount of ninety-two million three hundred sixty-two thousand ($92,362,000) dollars.

"**Event of Default**" has the meaning specified in Section 12.1.

"**Final Closing**" and "**Final Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

"**Final Investment Closing**" means 10:00 a.m. on the Final Investment Date.

"Final Investment Date" means January 1, 2015.

"**Financial Year**" means, in relation to TPC, the financial year of TPC as determined by the board of directors of TPC.

"**Future Material Agreement**" has the meaning specified in Section 10.1(13).

"**GAAP**" means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the Canadian Institute of Chartered Accountants, or any successor Person at such time.

"**General Partner**" means 5022649 Manitoba Ltd., in its capacity as the general partner of the Limited Partnership, pursuant to the terms of the Limited Partnership Agreement.

"**Government Funds**" means any funds provided or advanced to NCN or TPC by Canada or Manitoba, or by any crown corporation, agency, department or instrumentality of Canada or Manitoba on the condition or requirement that such funds are to be used for investment through or by TPC in the Limited Partnership, and which TPC:

(i) uses to repay any principal amount outstanding under the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which, for greater certainty, does not include any other amount paid to Hydro under the Equity Credit Facility); or

(ii) uses to make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification;

and, for greater certainty, does not include any grants, loans or funds provided or advanced by any of the said parties to NCN or TPC without any condition or requirement that such grants, loans or funds are to be used for investment through or by TPC in the Limited Partnership, in which event the said grants, loans or funds will, after TPC's repayment of an Advance or payment to the Limited Partnership, as applicable, form part of TPC's Own Funds hereunder, without further qualification as "Government Funds".

"**Government of Canada Yield**" means for any particular date, the yield to maturity on such date compounded semi-annually which a non-callable Government of Canada bond would carry if issued, in Canadian Dollars, at 100% of its principal amount on such day at 10:00 a.m. (Winnipeg time) with a term to maturity equal to the remaining term to Maturity for the Equity Credit Advance that is being repaid. The Government of Canada Yield will be the yield determined by Hydro obtaining three rate quotes from investment dealers and using the median of the three rate quotes obtained.

"**Governmental Entity**" means any:

(i) federal, provincial, state, regional, municipal, local or other government, governmental or public department, central bank, court, commission, board, bureau, agency or instrumentality, domestic or foreign;

(ii) any agent, commission, board, or authority of any of the foregoing; or

(iii) any body exercising any regulatory, expropriation or taxing authority under or for the account of any of the foregoing except not including Hydro for the purposes of this Agreement.

Hydro" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the Hydro Act.

"**Hydro Act**" means *The Manitoba Hydro Act*, R.S.M. 1987, c. H190, as amended from time to time.

"**Hydro's Account**" means such account or accounts maintained by Hydro at the Royal Bank of Canada, as Hydro from time to time notifies TPC for the purposes of this Agreement.

"**Hydro Liens**" means:

(i) Liens in favour of Hydro created by the Security Documents hereunder or by the Security Documents (as defined in the NCN Financing Agreement); and

(ii) Liens in favour of Hydro created by the Revenue Advance Consolidation Agreement and the security agreements provided by TPC to Hydro pursuant to that agreement.

"**Initial Closing**" **and** "**Initial Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

Initial Limited Partnership Agreement" means the limited partnership agreement entered into between the General Partner, in its capacity as general partner, and Hydro, as limited partner, dated the 9^{th} day of December, 2004.

"**Initial TPC Financing Agreement**" means the TPC Financing Agreement entered into between TPC and Hydro dated June 28, 2006 which agreement remained in effect to and including March 31, 2015.

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards, or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws.

"**Lien**" means, with respect to any Property, any charge, mortgage, pledge, hypothecation, security interest, lien, conditional sale (or other title retention agreement or lease in the nature thereof), lease, servitude, assignment, adverse claim, defect of title, restriction, trust, or other encumbrance of any kind in respect of such Property, whether or not filed, recorded or otherwise perfected under applicable Laws.

"**Limited Partner**" means one of Hydro or TPC, as the context requires, in its capacity as a limited partner of the Limited Partnership, and "**Limited Partners**" means both of Hydro and TPC, in their respective capacities as limited partners of the Limited Partnership.

"**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement and continued pursuant to the Limited Partnership Agreement, for the purposes of owning and directly or indirectly planning, designing, constructing, operating and maintaining the Wuskwatim Project.

"**Limited Partnership Account**" means the Canadian Dollar account maintained by the Limited Partnership at Royal Bank of Canada, the particulars of which shall have been notified by the Limited Partnership to Hydro.

"**Limited Partnership Agreement**" means the Third Amended and Restated Limited Partnership Agreement amending and restating the second Limited Partnership Agreement, dated even date herewith between the General Partner, in its capacity as general partner, and Hydro and TPC, in their respective capacities as limited partners.

"**Limited Partnership Payment Certification**" has the meaning specified in Section 10.2(11).

"**Loan Documents**" means this Agreement, the Security Documents, and all other agreements, certificates and instruments delivered or given pursuant to or in connection with this Agreement; and "**Loan Document**" means any one of such Loan Documents.

"**Loss**" means any loss whatsoever, whether direct or indirect, including expenses, costs, damages, judgments, penalties, fines, charges, claims, demands, liabilities, debts, interest, any and all legal fees and disbursements on a solicitor and his own client basis.

"**Manitoba**" means the Government of Manitoba.

"**Market Make-whole Payment**" has the meaning specified in Section 13.11.

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in or of itself but which cumulatively results in a material adverse effect) on:

(i) the ability of TPC to perform any of its material obligations under the Loan Documents; or

(ii) the ability of Hydro to enforce any of the material obligations of TPC under the Loan Documents, where Hydro, acting reasonably, has determined that its ability to enforce the said material obligations cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected, notwithstanding that TPC has provided its written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said material obligations of TPC under the Loan Documents.

"**Material Agreements**" has the meaning specified in Section 9.1(11).

"**Maturity Date**" means the fiftieth Anniversary Date.

"**Maturity Sale Conditions**" means:

(i) NCN owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of Chief and Council of NCN);

(ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Maturity Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing, and TPC has the full right to sell and transfer the Maturity Sale Units to Hydro;

(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Maturity Sale Units other than Hydro;

(iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment or right for the purchase of any of the Capital Stock of TPC; and

(v) the consummation of the transactions contemplated by the exercise of the Maturity Sale Right will not result in the creation or imposition of any Lien on the Maturity Sale Units (other than such other Liens as Hydro, on the Maturity Date, may in its unfettered discretion accept in writing).

"**Maturity Sale Right**" has the meaning specified in Section 5.1(b).

"**Maturity Sale Units**" has the meaning specified in Section 5.1(b).

"**NCN**" means the Nisichawayasihk Cree Nation, formerly known as the Nelson House First Nation.

"**NCN Business**" has the meaning ascribed thereto in the PDA.

"**NCN Deed of Assignment**" has the meaning ascribed thereto in the PDA.

"**NCN Financing Agreement**" means the amended and restated financing agreement dated April 16, 2015 between NCN, TPC, and Hydro.

"**Notice**" means any notice, citation, directive, request for information, writ, summons, and statement of claim or other communication from any Person.

"**Notice of Sale**" has the meaning specified in Section 5.5.

"**Obligations**" has the meaning specified in Section 11.1.

"**PDA**" means the Project Development Agreement dated June 26, 2006 made between NCN, Hydro, TPC, the General Partner and the Limited Partnership as supplemented and amended by PDA Supplement No. 1 dated March 15, 2011 and PDA Supplement No. 2 dated April 16, 2015.

"**Permitted Liens**" means, with respect to any Person, any one or more of the following:

(i) Liens for Taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such taxes, assessments and charges;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(ii) Liens resulting from any judgment rendered or Claim filed against such Person which such Person shall be contesting in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such judgment or Claim;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(iii) undetermined Liens arising in the ordinary course of business which have not at such time been filed pursuant to Law against such Person or which relate to obligations not due or delinquent;

(iv) Liens arising in the ordinary course of business which are not registered against title to the Collateral and are not overdue for a period of more than thirty (30) days or which are being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion, (i) adequate security has been provided to ensure payment of such Liens; (ii) adequate reserves with respect thereto are maintained on the consolidated books of such Person in accordance with GAAP; and (iii) in each case, such Liens will not materially interfere with use of such Property by the Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(v) any Lien, payment of which has been provided for by the depositing with Hydro of an amount in cash, or the obtaining of a surety bond satisfactory to Hydro, in its absolute discretion, sufficient in either case to pay or discharge such Lien and which deposit or bond Hydro is authorized to use or draw upon for that purpose;

(vi) Liens securing Purchase Money Debt provided that: (i) such Liens shall extend only to the specific Property of the Person acquired with the proceeds of such Purchase Money Debt (and not any portion of the Collateral) and (ii) recourse in respect of such Liens shall be limited to such specific Property;

(vii) the Hydro Liens; or

(viii) any other Lien approved in writing in advance by Hydro, in its unfettered discretion.

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture, Band within the meaning of the *Indian Act* (Canada) or other entity or Governmental Entity, and pronouns have a similarly extended meaning.

"**Property**" means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including capital stock in any other Person.

"**Purchase Money Debt**" means, with respect to any Person, all obligations of such Person incurred to finance the acquisition of Property.

"**Receiver**" means a receiver, receiver and manager or other person having similar powers or authority appointed by Hydro or by a court at the instance of Hydro in respect of the Collateral or any part thereof.

"**Repayment Notice**" has the meaning specified in Section 4.5.

"**Revenue Advance Consolidation Agreement**" has the meaning ascribed thereto in the PDA.

"**Sale**" means a transaction of purchase and sale of all or a portion of TPC's Units pursuant to Article V.

"**Sale Certificates**" has the meaning specified in Section 7.1(2)(a).

"**Sale Closing Date**" has the meaning specified in Section 7.1(1)(a).

"**Sale Units**" means the, the Twenty-Fifth Anniversary Sale Units, the Maturity Sale Units or the Term Sale Units, as the context requires.

"**Security Documents**" means those agreements and other documents in favour of Hydro described in Schedule G, in form and substance satisfactory to Hydro, acting reasonably, as such documents may be amended or restated from time to time, as security for all or any portion of the Obligations.

"**Short-Term Canadian Borrowing Cost**" means, for any month, Hydro's actual weighted average borrowing cost (which, it is acknowledged, includes the Canadian Dollar Guarantee Rate) expressed as a percentage rate per annum for all of Hydro's Canadian Dollar borrowings outstanding during that month which have a term expiring, or are due to be paid, within three hundred and sixty-four (364) days in length of the date that each such borrowing was first incurred by Hydro. Hydro's "actual weighted average borrowing cost" shall be calculated on the basis of the actual amount of interest that has accrued during that month divided by the "weighted principal amount" of all borrowing(s) which accrued interest during that month. The "weighted principal amount" for each borrowing is equal to the principal amount of each borrowing multiplied by the number of days the borrowing was outstanding during the month divided by 365.

"**TPC**" means Taskinigahp Power Corporation, a corporation that is wholly owned by NCN beneficially, and by the Chief or a Councillor of NCN, as registered owner as bare trustee for NCN.

"**TPC's Cash Units**" means:

(i) on the Final Investment Date that number of TPC's Units equal to (A) divided by (B) where (A) equals the number of TPC's Units on the Final Investment Date multiplied by TPC's Invested Cash as of that date; and (B) equals the sum of: (i) the aggregate of the amount of Equity Credit Advances which remain outstanding on that date; and (ii) TPC's Invested Cash as of that date; and

(ii) on any particular day after the Final Investment Date (the "**Measurement Date**") until the date that the Equity Credit Facility has been paid in full, that number of TPC's Units equal to (A) divided by (B) where (A) is the product of: (i) the number of TPC's Cash Units on the Final Investment Date, multiplied by (ii) the number of TPC's Units on the Measurement Date; and (B) equals the number of TPC's Units on the Final Investment Date; and

For greater certainty, on the date when the Equity Credit Facility has been paid out in full, all of TPC's Units shall be deemed to be TPC's Cash Units.

"**TPC's Invested Cash**" means on any particular day, the sum of all amounts invested by TPC in the Limited Partnership using Approved Funds. For greater certainty:

(i) this does not include the proceeds of Equity Credit Advances;

(ii) this does not include any amount for interest, costs, expenses or indemnity reimbursed or paid to Hydro hereunder; and

(iii) this does include all of TPC's Own Funds (which includes Government Funds) and all of TPC's Third Party Funds used by TPC either:

(A) to repay any principal amount outstanding under a Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification; or

(B) to make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification (including, without limitation, TPC's Cash Subscription Payment);

all of which amounts shall, after approval has been granted by Hydro, constitute Approved Funds.

"TPC's Loan Units" means, on any particular day, all of TPC's Units on that day that are not TPC's Cash Units.

"TPC's Own Funds" means any funds that TPC will use to:

(i) repay any principal amount outstanding under the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which, for greater certainty, does not include any other amount paid to Hydro under the Equity Credit Facility);

(ii) make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification; or

(iii) make TPC's Cash Subscription Payment;

provided that the said funds have not been obtained by TPC (whether directly or indirectly through NCN, an NCN Business or the Taskinigahp Trust) from any arm's length Person, in any material way due to or as a result of:

(A) TPC being the owner of one or more Units; or

(B) TPC, NCN or Taskinigahp Trust providing or agreeing to provide, directly or indirectly, a Lien in favour of any other Person on, or by TPC, NCN or the Taskinigahp Trust conferring an ownership or proprietary interest or any kind upon any other Person, in any Property of TPC or the Property of Taskinigahp Trust (provided that this is not intended to prohibit or restrict the beneficial interest of the beneficiaries of the Taskinigahp Trust under the Trust Indenture constituting the Taskinigahp Trust), the Capital Stock of TPC, TPC's Units or any Distributions on the TPC's Units, or on any Corporate Distributions of TPC, including assignments or orders to pay.

For greater certainty, the mere investment of funds by NCN, an NCN Business or the Taskinigahp Trust in TPC for use by TPC in either repaying any principal amount under the Equity Credit Facility or making a payment to the Limited Partnership in the manner referenced above shall not preclude such funds from constituting TPC's Own Funds, and any funds so invested by NCN, an NCN Business or the Taskinigahp Trust in TPC shall be considered in all respects to be TPC's Own Funds for the purposes of this Agreement if Hydro determines that the funds otherwise fall within the definition of TPC's Own Funds in accordance with the provisions of this Agreement (and, for this purpose, Hydro shall be entitled to look to the source of the funds to NCN, the NCN Business or the Taskinigahp Trust). Government Funds (once approved as such by Hydro pursuant to the approval processed hereunder) and funds obtained by TPC from Distributions on TPC's Units or from earnings on the investment of Distributions on TPC's Units which are voluntarily used to repay any principal amount (but no other amount) under the Equity Credit Facility or which are invested in the Limited Partnership pursuant to a Credit Facility Repayment Certification or a Limited Partnership Payment Certification respectively shall be deemed for the purposes of this Agreement to be TPC's Own Funds (but, for greater certainty, amounts paid to Hydro pursuant to the irrevocable assignment and direction of Distributions on TPC's Units under the Security Documents shall not count or be included as part of TPC's Own Funds).

"**TPC's Third Party Funds**" means any funds that TPC will use to either:

(i) repay any principal amount under the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which for greater certainty does not include any other amount paid to Hydro under the Equity Credit Facility); or

(ii) make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification;

which are not TPC's Own Funds. For greater certainty:

(A) the mere assignment of Dividends by NCN to the Taskinigahp Trust pursuant to the NCN Deed of Assignment shall not be deemed to constitute any of TPC's funds as being TPC's Third Party Funds hereunder;

(B) merely because funds have been obtained by NCN from a third party, whether by loan, grant, subsidy or otherwise shall not be sufficient for such funds to be deemed to be TPC's Third Party Funds; and

(C) none of NCN, any NCN Business or the Taskinigahp Trust shall be deemed to be a third party for the purposes of determining what funds are TPC's Own Funds and what funds are TPC's Third Party Funds, provided however, that where the source of any funds is any of NCN, an NCN Business or the Taskinigahp Trust, Hydro is entitled to look beyond such party to determine the ultimate source of such funds in applying the provisions hereof.

"**TPC's Units**" means, at any time, the Units owned by TPC.

"Taskinigahp Trust" has the meaning ascribed thereto in the PDA.

"**Taxes**" means all taxes imposed by any Governmental Entity, including real property, personal property, goods and services, sales, transfer, purchase, stumpage, registration, capital, excise, import duties, payroll, unemployment, disability, employee's income withholding, social security or withholding.

"**Ten Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of ten years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian Dollar non-callable Government of Canada reference bonds with a ten year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the ten year term, and using the median rate of the three rate quotes obtained).

"**Ten Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba, at 100% of the principal amount for a term of ten years.

"**Term Sale Conditions**" means:

(i) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Term Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing;

(ii) TPC has the full right to sell and transfer the Term Sale Units to Hydro;

(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Term Sale Units other than Hydro; and

(iv) the consummation of the transactions contemplated by the exercise of the Term Sale Right will not result in the creation or imposition of any Lien on the Term Sale Units (other than such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing).

"Term Sale Right" has the meaning specified in Section 5.1(c).

"**Term Sale Units**" has the meaning specified in Section 5.1(c).

"**Thirty Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of thirty years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian Dollar non-callable Government of Canada reference bonds with a thirty year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the thirty year term, and using the median rate of the three rate quotes obtained).

"**Thirty Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba at 100% of the principal amount for a term of thirty years.

"**Total Outstandings**" means the aggregate amount in Canadian Dollars of all outstanding Advances at any time under the Equity Credit Facility but does not include any interest, costs, expenses or indemnity claim arising under the Equity Credit Facility.

"**Twenty-Fifth Anniversary Sale Conditions**" means:

(i) NCN owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of the Chief and Council of NCN);

(ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Twenty-Fifth Anniversary Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing, and TPC has the full right to sell and transfer the Twenty-Fifth Anniversary Sale Units to Hydro;

(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Twenty-Fifth Anniversary Sale Units other than Hydro;

(iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment or right for purchase of any of the Capital Stock of TPC; and

(v) the consummation of the transactions contemplated by the exercise of the Twenty-Fifth Anniversary Sale Right will not result in the creation or imposition of any Lien on the Twenty-Fifth Anniversary Sale Units (other than such other Liens as Hydro, on the Sale Closing Date, may accept in writing in its unfettered discretion).

"**Twenty-Fifth Anniversary Sale Right**" has the meaning specified in Section 5.1(a).

"**Twenty-Fifth Anniversary Sale Units"** has the meaning specified in Section 5.1(a).

"**Unit**" means one of the units in the Limited Partnership issued to and subscribed for by a Limited Partner pursuant to the Limited Partnership Agreement, and "**Units**" means all of the issued Units in the Limited Partnership.

"**Wuskwatim Project**" has the meaning ascribed thereto in the PDA.

1.2 <u>Interpretation.</u>

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, any other Loan Documents or any provisions hereof or thereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(e) the expressions "the aggregate", "the total", "the sum" and expressions of similar meaning shall mean "the aggregate (or total or sum) without duplication";

(f) in the computation of periods of time, unless otherwise expressly provided, the word "from" means "from and including" and the words "to" and "until" mean "to but excluding";

(g) accounting terms not specifically defined shall be construed in accordance with GAAP. Except as otherwise mandated by changes in GAAP from time to time, the financial statements required to be delivered pursuant to this Agreement shall be prepared, and all calculations made for the purposes of this Agreement shall be made, unless otherwise provided for herein, by the application of GAAP applied on a basis consistent with the most recent audited financial statements of TPC, previously delivered to Hydro; and

(h) for the purposes of this Agreement, a Person (the "**first Person**") shall be deemed to be "**Controlled**" by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

(i) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

(ii) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person;

and "**Control**" and "**Controlling**" shall have corresponding meanings.

1.3 <u>Interpretation of any other Loan Documents.</u>

The provisions of Article 1.2 shall apply to the interpretation of all of the other Loan Documents unless specifically otherwise indicated therein.

1.4 **Severability.**

If any provision of this Agreement or any other Loan Document is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement or such other Loan Document and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions hereof or thereof shall be unaffected by such provision and shall continue to be valid and enforceable.

1.5 **Entire Agreement.**

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the parties relating to the subject matter hereof and entered into prior to the date of this Agreement.

1.6 **Waiver.**

No failure on the part of Hydro to exercise, and no delay in exercising, any right under this Agreement or any other Loan Document shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement or any other Loan Document preclude any other or further exercise thereof or the exercise of any other right, nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No notice to or demand on TPC in any case shall entitle it to any notice or demand in similar or other circumstances, unless such notice or demand is required under the terms of this Agreement or the applicable Loan Document. No waiver of any of the provisions of this Agreement or any other Loan Document shall be effective unless it is in writing duly executed by the waiving party.

1.7 **Governing Law.**

This Agreement and each other Loan Document, shall be governed by, and interpreted in accordance with, the Laws of Manitoba and the Laws of Canada applicable therein.

1.8 Incorporation of Schedules.

The following schedules attached shall, for all purposes hereof, be incorporated in and form an integral part of this Agreement:

Schedule A	Repayment Notice
Schedule B	Intentionally Deleted
Schedule C	Issued and Outstanding Capital Stock and Debt
Schedule D	Material Agreements
Schedule E	Liabilities
Schedule F	Address for Notice
Schedule G	List of Security Documents
Schedule H	Authorizations - Hydro

It is acknowledged by Hydro that Schedules C to E (both inclusive) were delivered by TPC to Hydro on or before the Initial Closing Date for attachment to the Initial TPC Financing Agreement, which said Schedules shall be deemed to form part of this Agreement.

1.9 Conflicts.

If a conflict or inconsistency exists between a provision of this Agreement and a provision of any of the other Loan Documents or any part thereof, then the provisions of this Agreement shall prevail. Notwithstanding the foregoing, if there is any right or remedy of Hydro set out in any of the other Loan Documents or any part thereof which is not set out or provided for in this Agreement, such additional right or remedy shall not constitute a conflict or inconsistency.

ARTICLE II
EQUITY CREDIT FACILITY

2.1 Equity Credit Facility.

Hydro made, on the terms and conditions of the Initial Agreement, ninety-two million three hundred sixty-two thousand ($92,362,000) dollars in advances to TPC pursuant to the Equity Credit Facility to October 14, 2014, exclusive of accrued interest. The terms of this Agreement shall govern the financing and repayment of the Equity Credit Facility and accrued interest as of the Final Investment Date.

2.2 Non-Revolving Facility

The Equity Credit Facility is a non-revolving credit facility and the principal amount of any Advance that is repaid may not be re-borrowed and shall be a permanent reduction of the Equity Credit Facility Commitment.

2.3 Repayment on the Maturity Date.

Subject to Hydro making an early demand for payment pursuant to Section 12.1 following an Event of Default, TPC shall repay on the Maturity Date, the Total Outstandings, if any, under the Equity Credit Facility and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility, and the Total Outstandings, if any, under the Equity Credit Facility and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility shall become due and payable on the Maturity Date. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.

2.4 Balances as at Final Closing and TPC Payments.

The Parties agree and acknowledge that, at the Time of Final Investment Closing, TPC shall comply with each of the following conditions: ;

(a) TPC's Invested Cash is twenty-one million, one hundred and seventy-eight thousand ($21,178,000.00) dollars, exclusive of accrued interest;

(b) The Total Outstandings under the Equity Credit Facility is eight-seven million six hundred twelve thousand dollars ($87,612,000.00); and

(c) In addition to all other mandatory payment obligations provided for in this Agreement and subject to TPC's right to make prepayments in accordance with the provisions of this Agreement, TPC shall throughout the term of this Agreement repay to Hydro all outstanding Advances under the Equity Credit Facility and accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility solely through Hydro receiving all Distributions from time to time on TPC's Loan Units. The Distributions on TPC's Loan Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Equity Credit Facility; second, in payment of all accrued and unpaid interest under the Equity Credit Facility (except as dealt with under subsection (2) above); and third, in repayment of all principal amounts that have not been repaid under the Equity Credit Facility (except as dealt with under subsection (2) above). (For greater certainty, any of the said amounts owing under the Equity Credit Facility on the Maturity Date shall be required to be repaid on the Maturity Date in accordance with Section 2.5). Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until the Total Outstandings under the Equity Credit Facility and any accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity

Credit Facility have been repaid in full. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents. The amount of any repayment shall be a permanent reduction of the Equity Credit Facility Commitment.

2.5 Optional Reductions.

TPC may subject to the provisions of this Agreement, including Sections 4.5 and 4.6 as adjusted for the applicable Market Make-whole Payment in accordance with Section 13.11, prepay, in whole or in part, only with Approved Funds, the Total Outstandings under the Equity Credit Facility, at any time, without penalty as long as each partial prepayment made by TPC under the Equity Credit Facility shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.

ARTICLE III
PRIORITY OF DISTRIBUTION PAYMENTS

3.1 [intentionally blank]

3.2 [intentionally blank]

3.3 [intentionally blank]

3.4 [intentionally blank]

3.5 [intentionally blank]

3.6 [intentionally blank]

3.7 <u>Priority of Distribution Payments Prior to Maturity Date.</u>

Hydro shall apply all payment of Distributions on TPC's Units prior to Maturity Date on as follows:

(a) first, to the payments to be made to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), which shall have priority over any payments to be made out of Distributions on TPC's Units and the security provided to Hydro pursuant to the provisions of this Agreement, and accordingly, any such payments to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement shall not constitute an Event of Default hereunder;

(b) second, to the payments to be made to Hydro pursuant to Section 2.5(1) of the NCN Financing Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), and, accordingly, any such payments to Hydro pursuant to the NCN Financing Agreement shall not constitute an Event of Default;

(c) third, to the payments to be made to Hydro pursuant to Section 2.5(2) of the NCN Financing Agreement and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units, and any such payments to Hydro pursuant to the NCN Financing Agreement shall not constitute an Event of Default under this Agreement; and

(d) fourth to payments to be made to Hydro pursuant to Section 2.4 (c).

3.8 <u>Priority of Distributions Payments on Maturity Date.</u>

The priority for payments made to Hydro through Distributions on TPC's Units commencing on the Maturity Date shall be as follows:

(a) first, to the payments to be made to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), which shall have priority over any payments to be made out of Distributions on TPC's Units after the Maturity Date (and the security provided to Hydro pursuant to the provisions of this Agreement) and accordingly, any such payments to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement shall not constitute an Event of Default hereunder;

(b) second, to the payments to be made to Hydro pursuant to the provisions of the NCN Financing Agreement (and the security provided to Hydro pursuant to the provisions of that Agreement in respect of Distributions on TPC's Units); and

(c) for so long as no Event of Default has occurred that remains outstanding and uncured, and provided that Distributions on TPC's Units are applied in accordance with Section 3.8 (a) prior to the Maturity Date, and in accordance with Section 3.8(b) after the Maturity Date, pursuant to the irrevocable assignment and direction of the Distributions on TPC's Units to Hydro under the Security Documents as and when such Distributions are paid by the Limited Partnership (in the discretion of the General Partner), TPC shall have no other payment obligation under the Equity Credit Facility or in respect of any amounts (whether principal, interest, costs or otherwise) due thereunder (except at Maturity Date in respect of such amounts as are stated to be due and payable on the Maturity Date).

ARTICLE IV
LOAN ADVANCES

4.1 Interest on Equity Credit Advances.

Subject to Section 13.3, each Equity Credit Advance, or the amount remaining outstanding from time to time, shall bear interest calculated and payable in the following manner:

Any Equity Credit Advance forwarded to the Limited Partnership Account for the credit of TPC on or before October 14, 2014 shall:

(i) until the Final Closing Date bear interest at a variable rate (expressed as a percentage rate per annum) equal to the Canadian Dollar Floating Rate in effect from time to time, plus one (1%) percent per annum compounded monthly (not in advance), calculated (but not compounded) daily and shall accrue interest at that rate until the Final Closing Date. Hydro shall provide TPC with notice of the Canadian Dollar Floating Rate applicable to each such Equity Credit Advance, and it's supporting calculations therefore, which shall constitute, in the absence of error, prima facie evidence of the Canadian Dollar Floating Rate applicable to each such Advance;

(ii) from and after the Final Closing Date to and until March 31, 2014, the Total Outstandings under the Equity Credit Facility, plus all accrued and unpaid interest thereon, and all other amounts owing to Hydro under the Equity

Credit Facility as at the Final Closing Date shall bear interest at a fixed interest rate of six and three hundred seventy-six one thousands (6.376%) percent calculated and compounded semi-annually (not in advance). Hydro shall provide TPC with notice of the Canadian Thirty Year Rate applicable to the amount of the Equity Credit Advances then outstanding and all accrued and unpaid interest thereon and all other amounts owning to Hydro in respect thereto, and its supporting calculations therefore, which shall constitute, in the absence of error, prima facie evidence of the applicable Canadian Thirty Year Rate;

(iii) from and after April 1, 2014, the Total Outstandings under the Equity Credit Facility, plus all accrued and unpaid interest thereon, and all other amounts owing to Hydro under the Equity Credit Facility shall bear interest at a fixed interest rate of five and three hundred seventy-six one thousandth (5.376%) percent calculated and compounded semi-annually (not in advance);

Interest on any Equity Credit Advance made after April 1, 2014 shall accrue in the current month and added to the Total Outstandings for the purposes of the interest calculations in Section 13.3(a) (ii).

Hydro shall provide TPC with notice of the interest rate applicable to the amount of the Equity Credit Advances then outstanding, and all accrued and unpaid interest thereon and all other amounts owing to Hydro in respect thereto and its supporting calculations therefor; and

(iv) subject to the provisions of this Agreement (including payments made through Distributions under Article II and TPC's right to make prepayments in accordance with the provisions of this Agreement), the accrued interest, and all other amounts owing to Hydro under the Equity Credit Facility, shall only become due and payable on the Maturity Date.

Any Equity Credit Advance forwarded to the Limited Partnership Account for the credit of TPC after the Final Closing Date and prior to the first Anniversary Date shall, from the date of the Advance until March 31, 2014, bear interest at the interest rate established pursuant to Section 4.1(a) (ii) and, from and after April 1, 2014, bear interest at the interest rate established pursuant to Section 4.1(a) (iii), the provisions of which shall apply, *mutatis mutandis*, to such Advances and, subject to the provisions of this Agreement (including payments made though Distributions under Article II and TPC's right to make prepayments in accordance with the provisions of this Agreement), the accrued interest, and all other amounts owing to Hydro under the Equity Credit Facility, shall only become due and payable on the Maturity Date.

4.2 <u>Repayment Notice.</u>

Mandatory repayments pursuant to Sections 2.6(3) and (4) and optional repayment to reduce the Total Outstandings under the Equity Credit Facility pursuant to Sections 2.7 and/or 3.7 shall be made upon at least seven (7) Business Days' notice (but not more than twenty (20) Business Days' notice) to Hydro (each such notice a "**Repayment Notice**"). As a condition of any Repayment Notice and the payments being made to Hydro, TPC shall deliver to Hydro, at least thirty (30) calendar days prior to the proposed date that TPC intends to make the repayment, a statutory declaration signed by a duly authorized officer of TPC (each such statutory declaration a "**Credit Facility Repayment Certification**") which shall:

(a) certify the source of the money to be used for the proposed repayment;

(b) disclose all material information relating to the money to be used for the proposed repayment;

(c) attach true and complete copies of all material documents; and

(d) a copy of the proposed Repayment Notice in the form of Schedule A to this Agreement, specifying: (A) the proposed date of such repayment; and (B) the aggregate principal amount of the proposed repayment. Hydro shall have the right to request from TPC, within five (5) calendar days of receipt of the Credit Facility Repayment Certification, such additional information and notarized copies of documents relating to the monies to be used in respect of the proposed repayment as it may require, acting reasonably, and to receive such written consents and waivers from TPC to obtain additional information and documents from any other Person relating to the monies to be used in respect of the proposed repayment as Hydro may request, acting reasonably. Hydro shall be required to confirm in writing within twenty (20) calendar days of receipt of the Credit Facility Repayment Certification whether or not it will accept the Credit Facility Repayment Certification, unless the time period is extended by Hydro, acting reasonably, due to Hydro awaiting receipt of the additional information and documents as it may have requested in connection with the Credit Facility Repayment Certification.

4.3 <u>Hydro Acceptance of Repayment Notice.</u>

If Hydro accepts the Credit Facility Repayment Certification, TPC may issue to Hydro the Repayment Notice in the form attached to the Credit Facility Repayment Certification, and TPC shall:

(a) pay Hydro the repayment amount set out the Repayment Notice; and

(b) provide with the said payment, a statutory declaration signed by a duly authorized officer of TPC certifying there has been no material change to any of the information or documents provided by TPC in the Credit Facility Repayment Certification concerning the monies being paid to Hydro, including the source of the monies; and

(c) pay to Hydro all accrued interest on the Credit Facility in respect of which the repayment is being made, to the date of such repayment.

For greater certainty, any principal amount repaid pursuant to the Repayment Notice are Approved Funds and form part of TPC's Invested Cash but does not include any amount on account of the payment of accrued interest on the Equity Credit Facility).. Hydro shall be required to accept the Credit Facility Repayment Certification if Hydro determines, acting reasonably, that the monies being used for the repayment fall within the definition of TPC's Own Funds based on Hydro's analysis of the information disclosed and documents provided or otherwise obtained by Hydro.

4.4 <u>Hydro's Rejection of Funds.</u>

If Hydro, acting reasonably, based on its analysis, determines that the monies fall within the definition of TPC's Third Party Funds, then Hydro is entitled, to either reject or accept the Credit Facility Repayment Certification. In making that determination, Hydro will consider the source of the monies, the terms of any financing, any repayment requirements associated with the monies that have been provided, whether or not any Person has recourse against TPC's Units in the event of default in respect of any financing associated with obtaining the monies and, if so, the likelihood of that right being exercised. If Hydro rejects the Credit Facility Repayment Certification, TPC shall not be entitled to proceed with the proposed repayment.

4.5 <u>Hydro Acceptance of Certification.</u>

If Hydro accepts the Credit Facility Repayment Certification, the payment can be made and the funds will be Approved Funds and once the payment is made, it shall form part of TPC's Invested Cash. For greater certainty, any funds used by TPC from time to time to pay any interest, costs, expenses or indemnity claims properly due to Hydro hereunder having regard for Section 5.14 of the PDA, shall not require certification or approval hereunder as Approved Funds.

4.6 Evidence of Debt

The indebtedness of TPC in respect of all Advances shall be evidenced by the account records maintained by Hydro, which shall be prima facie evidence of such indebtedness for all purposes, absent error. Hydro shall indemnify and save harmless TPC for losses suffered or costs incurred by TPC due to Hydro's failure to correctly record or calculate any amount, rate, date or other data (including calculations to determine any amount) in the account records or in statements or notices issued to TPC where such failure was due to the gross negligence or willful misconduct of Hydro or any person for whom Hydro is responsible at law. Notwithstanding the foregoing, the failure of Hydro to correctly record or calculate, rate, date or other data (including calculations to determine any amount) in the account records or in statements or notices issued to TPC under this Agreement shall not, however, affect the obligation of TPC to pay amounts due hereunder to Hydro in accordance with this Agreement.

4.7 Determination of Interest and Fees

For purposes of the *Interest Act* (Canada):

(a) whenever any interest under this Agreement is calculated using a rate based on a period of time other than a calendar year, such rate determined pursuant to such calculation, when expressed as an annual rate, is equivalent to (x) the applicable rate based on such period of time multiplied by (y) the actual number of days in the calendar year in which the period for which such interest or fee is calculated ends, and divided by (z) the number of days in such period of time;

(b) the principle of deemed reinvestment of interest shall not apply to any interest calculation under this Agreement; and

(c) the rates of interest stipulated in this Agreement are intended to be nominal rates and not effective rates or yields.

4.8 Hydro Obligations.

Within ten (10) Business Days of the last day of each month during this Agreement, Hydro shall provide to TPC a written statement the Total Outstandings under the Equity Credit Facility on the last day of each month, together with the following information:

(a) opening and closing balances;

(b) principal repaid during the month;

(c) interest paid or payable by TPC, (together with the date(s) of any change(s) from floating rate(s) to fixed rate(s) charged on such Advances pursuant to the terms of this Agreement), during the month; and

(d) any costs charged by Hydro to TPC during the month, and any reimbursements made by TPC to Hydro during the month for costs charged by Hydro to TPC.

ARTICLE V
OPTIONS TO SELL TPC'S UNITS

5.1 TPC's Options To Sell.

The Parties acknowledge neither the Final Closing Sale Right or the Non-Completion Sale Right referenced in the Initial TPC Financing Agreement were exercised but this shall not preclude TPC from exercising the Term Sale Right, the Twenty-Fifth Anniversary Sale Right or the Maturity

Sale Right, in respect of any of TPC's Units still owned by TPC, which shall have the following rights:

(a) on the twenty-fifth Anniversary Date, a one time right, conditional only on TPC being in compliance with all of the Twenty-Fifth Anniversary Sale Conditions (the "**Twenty-Fifth Anniversary Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the twenty-fifth Anniversary Date (the "**Twenty-Fifth Anniversary Sale Units**"), and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Twenty-Fifty Anniversary Sale Units from TPC in accordance with and subject to the provisions of this Agreement;

(b) on the Maturity Date, a one time right, conditional only on TPC being in compliance with all of the Maturity Sale Conditions (the "**Maturity Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the Maturity Date (the "**Maturity Sale Units**"), and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Maturity Sale Units from TPC in accordance with and subject to the provisions of this Agreement; and

(c) at any time on or prior to the Maturity Date, a one-time right, conditional only on TPC being in compliance with the Term Sale Conditions, (the "**Term Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the date of exercise of such right (the "**Term Sale Units**"), and upon any exercise of such right, Hydro shall purchase all, and not less than all, of the Term Sale Units from TPC in accordance with the provisions of this Agreement.

Provided the Twenty-Fifth Anniversary Sale Right, Maturity Sale Right or Term Sale Right is exercised by TPC in the manner set out in this Agreement, and subject only to TPC's compliance with the Final Closing Sale Conditions, Non-Completion Sale Conditions, Twenty-Fifth Anniversary Sale Conditions, Maturity Sale Conditions, or Term Sale Conditions, as applicable, Hydro shall purchase all of the Twenty-Fifth Anniversary Sale Units, Maturity Sale Units or Term Sale Units, as applicable, in accordance with and subject to the terms of this Agreement.

5.2 Purchase Price 25th Anniversary Sale

The purchase price for the Twenty-Fifth Anniversary Sale Units which are sold to and purchased by, Hydro pursuant to the exercise by TPC of the Twenty-Fifth Anniversary Sale Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, the Total Outstandings defined under the NCN Financing Agreement and all accrued and unpaid interest, costs and other amounts owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant to each agreement, as of the twenty fifth Anniversary Date, and (B) is TPC's Invested Cash as at the twenty fifth Anniversary Date. The purchase price as so determined shall be paid in full by Hydro as follows:

(a) by Hydro accepting the Twenty-Fifth Anniversary Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility hereunder and under the Dividend Credit Facility (as defined under the NCN Financing Agreement), and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the twenty fifth Anniversary Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and

(b) by Hydro paying to TPC on the effective date of the sale of the Twenty-Fifth Anniversary Sale Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII; and the repayment effected thereby shall terminate the Equity Credit Facilities and the Dividend Credit Facility.

5.3 Purchase Price Maturity Date.

The purchase price for the Maturity Sale Units which are sold to and purchased by, Hydro pursuant to the exercise by TPC of the Maturity Sale Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, the Total Outstandings defined under the NCN Financing Agreement and all accrued and unpaid interest, costs and other amounts owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant to each agreement, as of the Maturity Date, and (B) is TPC's Invested Cash. The purchase price as so determined shall be paid in full by Hydro as follows:

(a) by Hydro accepting the Maturity Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility and the Dividend Credit Facility , and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant to each agreement as of the Maturity Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents under each agreement; and

(b) by Hydro paying to TPC on the effective date of the sale of the Maturity Sale Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII; and the repayment effected thereby shall terminate the Equity Credit Facility and the Dividend Credit Facility (as defined under the NCN Financing Agreement).

5.4 Purchase Price Term Sale.

The purchase price for the Term Sale Units which are sold to, and purchased by, Hydro, pursuant to the exercise by TPC of the Term Sale Right shall be an amount equal to the aggregate of the Total Outstandings under the Credit Facilities, the Total Outstandings defined under the NCN Financing Agreement and all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the effective date of the sale pursuant to the exercise by TPC of the Term Sale Right. The purchase price as so determined shall be paid in full by Hydro accepting the Term Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility and the Dividend Credit Facility and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant to each agreement, as of the effective date of the sale pursuant to the exercise by TPC of the Term Sale Right, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents pursuant to each agreement and the repayment shall terminate the Equity Credit Facility and the Dividend Credit Facility.

5.5 Exercise of TPC's Sale Rights and Hydro's Notice Covenant.

The Twenty Fifth Anniversary Sale Right and the Term Sale may only be exercised by giving notice to Hydro in the manner set out in Section 5.4 (a "**Notice of Sale**"). Hydro agrees to provide to TPC not less than forty five (45) calendar days, nor more than ninety (90) calendar days, prior written notice of the Twenty-Fifth Anniversary Date or the Maturity Sale Date, as applicable, which notice shall include the following information:

(a) Hydro's calculation of the number of TPC's Units that are TPC's Loan Units and the number that are TPC's Cash Units as of the date of the notice (together with its supporting calculations); and

(b) the Total Outstandings owing under the Equity Credit Facility, and the amount of any accrued interest and costs that is owing to Hydro, as of the notice date (having regard in respect of costs to Section 12.2).

5.6 Contents of a Notice of Sale.

A Notice of Sale shall only be effective if:

(a) it is executed by TPC and it indicates the number of TPC's Units in respect of which TPC is exercising its right to sell and, if the number of TPC's Units in respect of which its right to sell is being exercised is not specified in the Notice of Sale, TPC shall be deemed to be exercising its right to sell to Hydro all of TPC's Units;

(b) for the exercise of the Twenty-Fifth Anniversary Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the Twenty-Fifth Anniversary Date, together with a statement from TPC:

(i) confirming TPC has elected to sell the Twenty-Fifth Anniversary Sale Units pursuant to the Twenty-Fifth Anniversary Sale Right; and

(ii) representing and warranting that each of the Twenty-Fifth Anniversary Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;

(c) for the exercise of the Maturity Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the Maturity Date, together with a statement from TPC:

(ii) confirming TPC has elected to sell the Maturity Sale Units pursuant to the Maturity Sale Right; and

(iii) representing and warranting that each of the Maturity Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;

(d) for the exercise of the Term Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the proposed effective date of the sale of the Term Sale Units pursuant to the exercise of the Term Sale Right, together with a statement from TPC:

(i) confirming TPC has elected to sell the Term Sale Units pursuant to the Term Sale Right; and

(ii) representing and warranting that each of the Term Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC.

5.7 Effect of the Notice of Sale and Closing Arrangements.

If a Notice of Sale is sent to Hydro in compliance with Section 5.4, then:

(a) TPC shall be obligated to sell the applicable Sale Units to Hydro at the purchase price and in the manner determined in accordance with Section 5.2;

(b) Hydro shall be obligated to purchase the applicable Sale Units from TPC at the purchase price and in the manner determined in accordance with Section 5.2; and

(c) such Sale shall be completed on the date, at the place and in the manner determined in accordance with the provisions of Article VII.

ARTICLE VI

[Intentionally deleted]

ARTICLE VII
GENERAL TERMS AND CONDITIONS APPLICABLE TO ANY SALE

7.1 Application and Terms and Condition.

The following provisions of this Article VII shall apply to any Sale pursuant to Article V of this Agreement:

(1) Closing Date and Sale.

The Sale shall be completed on the date and at the place determined in accordance with the provisions of this Article VII:

(a) the Sale shall be completed:

(i) on the twenty-fifth Anniversary Date if the Sale is pursuant to the exercise of the Twenty-Fifth Anniversary Sale Right;

(ii) the Maturity Date if the Sale is pursuant to the exercise of the Maturity Date Sale Right;

(iii) on the date that is twenty-eight (28) calendar days after the Notice of Sale is issued if the Sale is pursuant to the exercise of the Term Sale Right;

as the case may be, provided, however, that the said Sale may occur on such other date that the parties may mutually agree upon (the "**Sale Closing Date**"); and

(b) the place for the completion of the Sale shall be the head office of Hydro in connection with the Sale or if applicable the law office of the external legal counsel of Hydro or such other place as the parties may mutually agree upon.

(2) Sale Closing Arrangements.

At or before the Sale Closing Date, TPC shall deliver the following to Hydro subject to Hydro complying with all required conditions on Hydro as set out in this Article VII, including payment to TPC in full of the purchase price for the Sale Units or:

(a) one or more certificates representing in the aggregate the Sale Units, duly endorsed in blank for transfer to Hydro (the "**Sale Certificate(s)**") or power of attorney appointing Hydro as attorney of TPC to transfer the Sale Units to Hydro, provided that where the number of Units represented by the Sale Certificate(s) exceed the number of Sale Units the transfer of the Sale Units to Hydro shall be conditional upon Hydro's receipt from the Limited Partnership of a replacement certificate, (unless the Equity Credit Facility under this Agreement have been terminated and the Dividend Credit Facility, as that term is defined under the NCN Financing Agreement, has been terminated and there are no outstanding Obligations under this Agreement or under the NCN Financing Agreement, as defined under that agreement, in which event the said certificate shall be forwarded to TPC), confirming TPC's ownership of that number of Units which is in excess of the number of Sale Units. Hydro is authorized to retain the replacement certificate(s) for such period of time as there are any outstanding Obligations under this Agreement or under the NCN Financing Agreement (as defined under that agreement) and Hydro agrees to provide copies to TPC of all of the said certificates, together with confirmation in writing that it is holding the originals of the said certificates immediately upon receipt thereof;

(b) such other documents as Hydro may reasonably require to entitle Hydro to require the General Partner to register the transfer of such Sale Units to Hydro and to entitle Hydro to become the registered holder of such Sale Units on the books of the Limited Partnership, free and clear of all Liens except the Permitted Liens (the particulars of which have been identified in writing to Hydro to the extent that TPC is aware of the existence of such Permitted Liens) and such other Liens as at the Sale Closing Date as Hydro may, in its unfettered discretion, accept in writing;

(c) a certificate bearing the date on which the Sale Closing Date occurs wherein TPC certifies in respect of the Sale Units as being true and correct, each of the Term Sale Conditions, the Twenty-Fifth Anniversary Sale Conditions, or the Maturity Sale Conditions, as applicable, as at the Sale Closing Date; and

(d) a certificate bearing the closing date wherein TPC certifies, as being true, as at the Sale Closing Date a statement to the effect that on such date TPC is resident in Canada for the purposes of the *Income Tax Act*.

(3) Title and other TPC Covenants.

At the Sale Closing Date, TPC shall transfer and deliver to Hydro good and marketable title to such Sale Units free and clear of all Liens except for the Permitted Liens (the particulars of which have been identified in writing to Hydro to the extent that TPC is aware of the existence of such Permitted Liens) and any -other Liens that Hydro, in its unfettered discretion, agrees in writing at the Sale Closing Date that the Sale may be subject to.

(4) Satisfaction of Purchase Price.

At the Sale Closing Date, Hydro shall satisfy the purchase price for the Sale Units to be purchased from TPC in the manner provided for in this Agreement, and in the event that the Sale Units constitute all of TPC's Units, Hydro shall arrange for discharge of all registrations in public registries made against TPC and/or NCN under the Security Documents pursuant to this Agreement and under the Security Documents pursuant to the NCN Financing Agreement (and the original Guarantee, as defined under the NCN Financing Agreement, shall be returned to TPC for cancellation).

7.2 Conditions to the Obligations of Hydro.

Notwithstanding anything in this Agreement, , the obligations of Hydro to complete the Sale of the Sale Units , shall, until the Sale has been completed, be subject to the fulfillment of the following conditions and TPC covenants and agrees to perform and comply with each and every one of such conditions insofar as such conditions relate to matters within the control of TPC:

(1) all terms, covenants, agreements and conditions of this Agreement which are to be complied with or performed by TPC at or before the Sale Closing Date shall have been complied with and performed in all material respects in accordance with the terms of this Agreement prior to or at such time; and

(2) at the Sale Closing Date, TPC shall, without limitation to all other obligations of TPC in respect of the Sale as set out in this Agreement execute and deliver to Hydro a certificate bearing the Sale Closing Date wherein a duly authorized officer of TPC shall certify as true, for and on behalf of TPC (and not in such officer's personal capacity), a statement to the effect that at such time the conditions set out in paragraph (1) above have been performed, complied with and fulfilled except as specifically disclosed in such certificate and the closing of the Sale shall not be effective unless and until Hydro accepts in writing any and all exceptions disclosed in such certificate.

The conditions applicable to a Sale of the Sale Units, contained in the provisions of this Section 7.2 are inserted for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro at any time without prejudice to the right of Hydro to rely on all covenants and agreements and representations and warranties in this Agreement and all conditions contained in this Section 7.2, except to the extent that Hydro has in writing waived its right to rely on such covenants, agreements, representations, warranties or conditions. If any of the conditions applicable to a Sale of the Sale contained in this Section 7.2 are not be fulfilled or complied with as herein provided, Hydro may, at its option:

(a) terminate the obligations of TPC and Hydro in respect of the Sale of the Sale Units by notice in writing to TPC and in such event Hydro and TPC shall be released from all obligations hereunder in respect of the Sale of the Sale Units

(b) defer the completion of the Sale of the Sale Units to a new closing date (not to exceed three (3) months after the original closing date except by agreement in writing of the parties) to determine if the aforesaid conditions can be fulfilled or complied with; or

(c) bring an action for specific performance or any other remedy which may be available to Hydro.

7.3 Conditions to the Obligations of TPC.

Notwithstanding anything herein contained, the obligations of TPC to complete the Sale of the Sale Units shall, until the Sale has been completed, be subject to the fulfillment of the following conditions and Hydro covenants and agrees to perform and comply with each and every one of such conditions insofar as such conditions relate to matters within the control of Hydro:

(1) all terms, covenants, agreements and conditions of this Agreement which are to be complied with or performed by Hydro at or before the Sale Closing Date shall have been complied with and performed in all material respects in accordance with the terms of this Agreement prior to or at such time; and

(2) at the Sale Closing Date, Hydro shall, without limitation to all other obligations of Hydro in respect of the Sale as set out in this Agreement, execute and deliver to

TPC a certificate bearing the Sale Closing Date wherein a duly authorized officer of Hydro shall certify as true, for and on behalf of Hydro (and not in such officer's personal capacity), a statement to the effect that the conditions set out in paragraph (1) above have been performed, complied with and fulfilled except as specifically disclosed in such certificate (and the closing of the Sale shall not be effective unless and until TPC accepts in writing any and all exceptions disclosed in such certificate).

The conditions applicable to a Sale of the Sale Units contained in the foregoing provisions of this Section 7.3 are inserted for the exclusive benefit of TPC in respect of the Sale of the Sale Units and may be waived in whole or in part by TPC at any time without prejudice to the right of TPC to rely on all covenants and agreements and representations and warranties in this Agreement and all conditions contained in this Section 7.3 except to the extent that TPC has in writing waived its right to rely on such covenants, agreements, representations, warranties or conditions. If any of the conditions applicable to a Sale of the Sale Units and contained in this Section 7.3 shall not be fulfilled or complied with as herein provided, TPC may, at its option:

(a) terminate the obligations of Hydro and TPC in respect of the sale of the Sale Units by notice in writing to Hydro and in such event TPC and Hydro shall be released from all obligations hereunder in respect of the Sale of the Sale Units;

(b) defer the completion of the Sale of the Sale Units to a new closing date (not to exceed three (3) months after the original closing date except by agreement in writing of the parties, to determine if the aforesaid conditions can be fulfilled or complied with; or

(c) bring an action for damages or specific performance or any other remedy which may be available to TPC.

7.4 **Power of Attorney.**

Subject to payment of the purchase price to TPC and subject to Section- 6.3 hereof, TPC hereby irrevocably nominates, constitutes and appoints Hydro, its attorney and agent, for, in the name of and on behalf of TPC to do all acts and things and sign all documents (other than any releases of Hydro, the General Partner or the Limited Partnership) which are necessary or desirable to complete the Sale of the Sale Units by TPC to perform, satisfy or discharge any obligations in relation to the Sale of the Sale Units or Purchased Units (as applicable) by TPC in connection with a Sale and, without limiting the foregoing, TPC acknowledges and agrees that Hydro is hereby granted authority to receive and accept delivery of and keep possession of, and to execute and deliver, in the name of and on behalf of TPC all such certificates, instruments and documents as may be necessary or desirable, (other than any releases of Hydro, the General Partner or the Limited Partnership) in the opinion of Hydro, acting reasonably, to complete any Sale of the Sale Units or to perform, satisfy or discharge any obligations in relation to a Sale of the Sale Units . TPC hereby acknowledges and agrees that the appointment hereby made and the powers hereby granted are coupled with an interest and are and shall be irrevocable and to the extent permitted by applicable Laws shall survive the dissolution, insolvency or bankruptcy of TPC and may be exercised by Hydro in its own name or in the name of TPC and shall survive any assignment or purported assignment of TPC's Units by TPC and to the extent permitted by applicable laws, shall be binding upon the successors and permitted assigns of TPC.

If Hydro, as attorney on behalf of TPC completes the Sale of the Sale Units Hydro shall be entitled to have any proceeds of the Sale, to which TPC would otherwise be entitled to receive, paid to legal counsel for Hydro (as designated by Hydro) to be held in trust for TPC, and to be retained by such legal counsel until TPC delivers to Hydro such documents as TPC is required to deliver under this Agreement to complete the Sale of the Sale Units. Promptly upon the receipt of such documents by Hydro, Hydro's legal counsel shall pay the applicable proceeds, and deliver any other applicable closing documents to which TPC is entitled, to TPC, together with such interest as legal counsel may have earned on such proceeds.

ARTICLE VIII

[Intentionally deleted.]

ARTICLE IX
REPRESENTATIONS AND WARRANTIES

9.1 Representations and Warranties.

To induce Hydro to make Advances available under this Agreement, TPC represents and warrants to Hydro that each of the following representations and warranties is true and correct:

(1) Status and Power. TPC is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has full corporate power and capacity to own its property and carry on its Business. TPC is duly qualified, licenced or registered to carry on business in Manitoba.

(2) Authorization. TPC has full power and capacity and full legal right to enter into and perform its obligation under this Agreement and each of the other Loan Documents to which it is or will be a party, and has or will have by the Initial Closing Date taken all action necessary to be taken by it to authorize such acts.

(3) Enforceability of Agreement. This Agreement and any other Loan Document to which TPC is a party constitutes legal, valid and binding obligations of TPC enforceable against it in accordance with their respective terms, subject only to any limitation under applicable Laws relating to (a) bankruptcy, insolvency, reorganization, moratorium or creditors' rights generally; and (b) the discretion that

a court, or an arbitrator duly appointed under Article XXI of the PDA, may exercise in the granting of equitable remedies.

(4) Government Approval and Regulation. No Authorization or approval or other action by, and no notice to or filing with, any Governmental Entity or other Person (other than those that have been, or by the Initial Closing Date will be, duly obtained or made) is required for the due execution, delivery or performance by TPC of any Loan Document to which TPC is a party.

(5) Litigation. There is no material action, suit or proceeding which has been commenced (Notice of which has been served on TPC), or to the best of the knowledge of TPC, pending or threatened against TPC before or by any Governmental Entity, or before any arbitrator or board, which would prevent TPC from performing its obligations under any of the Loan Documents to which it is a party. TPC is not in default with respect to any judgment, order, writ, injunction, decree, or award of any court, arbitrator, board or other Governmental Entity, nor is there any judgment, order, writ, injunction, decree, or award which would prevent TPC from performing its obligations under any of the Loan Documents to which it is a party.

(6) Imposition of Lien. The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents will not result in the creation or imposition of any Lien on any Property of TPC except as otherwise permitted by this Agreement.

(7) No Other Material Facts. None of:

(a) this Agreement;

(b) any of the other Loan Documents; or

(c) any certificate or statement in writing which has been supplied by or on behalf of TPC and is a document that is required to be delivered to Hydro pursuant to the provisions of the Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

(8) Restrictive Documents. TPC is not subject to, or a party to, any restriction in its constating documents or by-laws, any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement or any other Loan Documents or compliance by TPC with the terms, conditions and provisions hereof or thereof or the continuing operation of the Business.

(9) Title to Property. TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of its Property free and clear of all Liens, except Permitted Liens. TPC has full right to mortgage, pledge, charge and assign to Hydro the Collateral. No Person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Collateral other than Hydro.

(10) Compliance with Laws. TPC is in material compliance with all applicable Laws.

(11) No Breach of Contracts. Schedule D will be completed and provided by TPC to Hydro on or before the Initial Closing Date, and will, upon completion and deliver thereof, contain a complete and accurate list of all agreements to which TPC is a party in connection with the Corporate Distributions of TPC, the Capital Stock of TPC, the equity interest that NCN has in TPC, TPC's Units and Distributions on TPC's Units, and any other agreement to which TPC is a party creating liabilities or obligations upon any Person over the term of the agreement in excess of $75,000, or is otherwise material to TPC (collectively, the "Material Agreements"). TPC has provided, or will on or before the Initial Closing Date provide, copies of all of the Material Agreements, including amendments, or additions thereto, to Hydro. On the date of execution of each of the Future Material Agreements (as defined below in Section 10.1(14)), Schedule D hereto shall be deemed to be amended to include such Future Material Agreements and such Future Material Agreements shall be deemed to be "Material Agreements" for the purposes of this Agreement from and after such execution date, without the necessity of any further action by any of the parties hereto. Each Material Agreement is, or will on before Initial Closing Date be, in full force and effect, unamended (except as disclosed to Hydro), and there exists no default, or event, occurrence, condition or act (including the completion of the transactions contemplated in this Agreement and the other Loan Documents) which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a default thereunder. TPC has not violated or breached, in any respect, any of the terms or conditions of any Material Agreements and, to the best of the knowledge of TPC, all the material covenants to be performed by any other party thereto have been performed in all material respects.

(12) Books and Records. All books and records of TPC have been fully, properly and accurately kept and completed in accordance with GAAP and there are no material inaccuracies or discrepancies of any kind contained or reflected therein.

(13) Tax Liability. Except for any Taxes which are being diligently contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books:

(a) TPC has in a timely manner filed all tax returns, elections, filings and reports with respect to Taxes required by Law to be filed by it and such returns, elections, filings and reports are true, complete and correct;

(b) TPC has paid, or reserved in its financial statements, all Taxes which are due and payable, and has paid all assessments and reassessments and all other Taxes, governmental charges penalties, interest and fines due and payable by it;

(c) TPC has no liability, contingent or otherwise, for Taxes, except Taxes not now due and payable with respect to ordinary operations during the current fiscal period adequate provision for the payment of which has been made; and

(d) TPC has paid as and when due all applicable Taxes and remitted as required by Law all applicable Taxes and deductions and any interest or penalties related thereto.

(14) Shareholder. NCN is the beneficial owner of all of the Capital Stock of TPC free and clear of all Liens expect Permitted Liens. The Capital Stock of TPC is owned by the Chief or a Councillor of NCN, as bare trustee for NCN. No Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment, or right for purchase of any of the Capital Stock of TPC or to receive payment based on the value of any such Capital Stock. The issued and outstanding Capital Stock and Debt (excluding Debt under this Agreement) of TPC and the registered and beneficial holders of such Capital Stock and Debt (excluding Debt under this

Agreement) are, or will upon completion of delivery of Schedule C be, as described in Schedule C, which will be completed and provided by TPC to Hydro on or before the Initial Closing Date. Hydro acknowledges that the NCN Deed of Assignment shall not be deemed to be a breach of this representation.

(15) Liabilities. TPC does not have any liabilities, whether accrued, absolute, contingent or otherwise, of any kind or nature whatsoever, except as otherwise disclosed in Schedule E, which will be completed and provided by TPC to Hydro on or before the Initial Closing Date or pursuant to the Loan Documents, and except incurred after the date hereof in compliance with this Agreement and the Loan Documents.

(16) No Event of Default. No Event of Default has occurred, nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute an Event of Default under the Loan Documents. No default has occurred not has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute a default under any one or more Material Agreements which could result in the acceleration of amounts owing by TPC under any such Material Agreements.

(17) Financial Information. The financial statements of TPC furnished to Hydro pursuant to this Agreement have been prepared in accordance with GAAP consistently applied, and present fairly the financial portion of TPC as at the dates thereof and the results of TPC's operations for the periods then ended. All balance sheets, all statements of operations, shareholders' equity and cash flow and all other financial information of TPC furnished pursuant to Section 10.1(1) have been and will for periods following the Initial Closing be prepared in accordance with GAAP, consistently applied, and do or will present fairly the consolidated financial

position of TPC as at the dates thereof and the results of their operations for the periods then ended.

(18) Resident of Canada. TPC is a resident of Canada for the purposes of the Income Tax Act (Canada).

Each of the representations and warranties contained in this Section 9.1 shall be deemed to be continually repeated by TPC at the time of each Advance.

9.2 Survival of Representations and Warranties.

All the representations and warranties of TPC contained in Section 9.1 of this Agreement shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Equity Credit Facility has been terminated notwithstanding any investigation made at any time by or on behalf of Hydro.

9.3 Representations by Hydro.

To induce TPC to enter into this Agreement, Hydro represents and warrants to TPC that each of the following representations and warranties is true and correct:

(1) Hydro is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and each of the other Loan Documents to which it is a party and to perform its obligations hereunder and thereunder.

(2) This Agreement and the Loan Documents to which Hydro is a party have been duly authorized, executed and delivered by Hydro and are legal, valid and binding

obligations of Hydro, enforceable against Hydro by TPC to the extent that TPC is a party thereto, in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency and other Laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction, or, by this Agreement, at the discretion of the arbitrator.

(3) Subject only to obtaining the Authorizations described in Schedule H, the execution and delivery of this Agreement and each of the Loan Documents to which Hydro is a party and the consummation the transactions herein provided for by Hydro will not result in:

(a) the breach or violation of any other provisions of or constitute a default under or conflict with or cause the acceleration of any obligation of Hydro under:

(i) any contract to which Hydro is a party or by which it, or any of its property, is bound;

(ii) any provision of the constating documents, by-laws or resolutions of the Board of Directors (or any committee thereof) or shareholders of Hydro;

(iii) any judgment, decree, order or award of any court, governmental body or arbitrator having jurisdiction over Hydro; or

(iv) any applicable law, statue, ordinance, regulation or rule, including, without limitation, the *Hydro Act*; or

(b) the creation or imposition of any Lien on any investment transaction or any of the property or assets of Hydro;

(4) Hydro is a resident of Canada for the purposes of the Income Tax Act (Canada).

(5) None of:

(a) this Agreement;

(b) any of the Loan Documents; or

(c) any certificate or statement in writing which has been supplied by or on behalf of Hydro and is a document that is required to be delivered to TPC pursuant to the provisions of this Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

(6) There is no requirement for Hydro to make any filing with, give any notice to or obtain any license, permit, certificate, registration, authorization, consent or approval of any government regulatory authority as a condition to the lawful consummation by Hydro of the transaction contemplated by this Agreement and each other Loan Document to which it is a party, except as described in Schedule H.

Each of the representations and warranties contained in this Section 9.3 shall be deemed to be continually repeated by Hydro at the time of each Advance.

9.4 Survival of Representations and Warranties.

All the representations and warranties of Hydro contained in this Article IX shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Equity Credit Facility have been terminated notwithstanding any investigation made at any time by or on behalf of TPC.

ARTICLE X
COVENANTS OF TPC

10.1 Affirmative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has the Equity Credit Facility Commitment under this Agreement, and unless Hydro shall otherwise consent, TPC shall:

(1) **Financial Reporting and Deliveries**. Cause to be delivered to Hydro as soon as available, and in any event within one hundred and twenty (120) days after the end of each Financial Year, the audited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC for such Financial Year, in accordance with GAAP and subject to an unqualified opinion of the Auditors;

(2) **Additional Reporting and Deliveries**. Cause to be delivered to Hydro, following documents, in form and substance satisfactory to Hydro, acting reasonably:

(a) a copy of each management letter or report submitted to the board of directors (or any committee thereof) or senior management of any of TPC by the Auditors in connection with any annual, interim or special audit made by them of the books of TPC, together with the related response of TPC to be delivered promptly upon the issuance of the response by TPC;

(b) promptly after the occurrence of each Event of Default, a statement of TPC setting forth the details of such Event of Default and the action which TPC proposes to take or have taken with respect thereto;

(c) promptly after the commencement thereof, Notice of Claims which have been commenced against TPC (notice of which has been served on TPC, or to the best of the knowledge of TPC, have been commenced or are pending or threatened against TPC, for amounts which exceed $75,000 in the aggregate at any time or affect any of the Collateral;

(d) promptly after the occurrence of any material development with respect to any Claims referred to in Section 10.1(2)(c), and in any event within three (3) Business Days after TPC obtains knowledge of the occurrence thereof, Notice thereof to Hydro, and, to the extent Hydro requests them, copies of all documentation relating thereto; and

(e) such other information and reports relating to TPC, the Collateral or the Business, as Hydro may from time to time reasonably request.

(3) **Corporate Existence**. Preserve and maintain TPC's corporate existence.

(4) **Compliance with Laws**. Comply, in all material respects, with the requirements of all applicable Laws.

(5) **Payment of Taxes, Claims and Governmental Licence Fees**. Pay and discharge, before the same shall become delinquent:

(a) all Taxes, governmental assessments, charges or levies and Claims imposed upon it or upon any of its Property;

(b) all lawful Claims which, if unpaid, might by Law become a Lien upon its Property, in each case except for any such Tax, assessment, charge, levy or Claim which would result in a Lien which is a Permitted Lien; and

(c) all fees payable to Governmental Entities or other authorities in connection with all governmental licences issued to and held by TPC, (if any).

(6) **Keeping of Books**. Keep proper books, records and accounts, in which full and correct entries shall be made of all of TPC's financial transactions in accordance with GAAP.

(7) **Visitation and Inspection**. If, in the reasonable opinion of Hydro, an Event of Default has or may have occurred, at any reasonable time or times and upon reasonable prior notice given to TPC by Hydro permit Hydro or any of its authorized representatives, full and reasonable access to the premises of TPC and obtain any consents and waivers from any Person necessary, in the reasonable opinion of Hydro to ensure such access, for the purposes of inspecting (and, where required, taking copies of) the business, financial and computer records of TPC and to discuss the business, affairs, finances and accounts of, and the compliance by TPC with the terms of this Agreement and the other Loan Documents with the management and Auditors thereof.

(8) **Protect Hydro Liens**. At all times take all action and supply Hydro with all such information reasonably necessary to allow Hydro to create, maintain, perfect, protect and preserve the Liens provided for under the Security Documents and confer upon Hydro the security interest intended to be created thereby.

(9) **Payments**. Subject to Section 3.7(3), pay all amounts of principal, interest, costs and expenses on the dates, at the times and at the places specified in this Agreement or under any other Loan Document, but subject to the provisions of Section 12.2 in respect of costs and expenses.

(10) **Use of Proceeds.** Apply the proceeds of the Equity Credit Facility only in accordance with Sections 2.4 and 3.4.

(11) **Payment of Preferred Claims**. Pay, as and when due, any and all amounts which may result in a Lien on the Collateral under applicable Law (other than a Permitted Lien), whether or not such Lien is entitled to priority over the Liens in favour of Hydro under the Security Documents.

(12) **Loan Documents.** Execute and deliver to Hydro the Loan Documents.

(13) **Material Agreements**. Comply with the provisions of all of the Materials Agreements. In respect of each Material Agreement executed by TPC after the date hereof (each a "**Future Material Agreement**"), provide to Hydro a certified true copy of each Future Material Agreement.

(14) **Notice of Defaults.** TPC shall immediately notify Hydro:

(a) of any Event of Default or of any event, occurrence, condition or act which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become an Event of Default, or of any material default (either by

TPC or by any other party) under any Material Agreement or of any event which, with the giving of notice, the lapse of time or the happening of any other event or condition, would become a material default under or would otherwise allow the termination of any Material Agreement, and thereafter provide Hydro with all information reasonably requested by Hydro from time to time concerning the status thereof;

(b) on becoming aware of the occurrence of any litigation, dispute, arbitration, proceeding, labour or industrial dispute, the result of which if determined adversely would have a Material Adverse Business Effect on the ability of TPC to perform its obligations under this Agreement and the other Loan Documents, and thereafter provide Hydro with all information reasonably requested by Hydro concerning the status thereof.

(15) **Changes in Year End or Auditors.** TPC shall provide prior notice to Hydro of any changes in its Financial Year end or its auditors, specifying the new Financial Year end or auditors, as the case may be;

(16) **Further Assurances.** Upon request of Hydro, acting reasonably, duly execute and deliver or cause to be duly executed and delivered to Hydro such further instruments and other documents and do and cause to be done such further acts as may be necessary or desirable in the opinion of Hydro, acting reasonably, to carry out more effectively the provisions and purposes of the Loan Documents.

10.2 <u>Negative Covenants.</u>

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Credit Facility Commitment under this Agreement and unless Hydro, as the case may be, shall otherwise consent, TPC agrees not to:

(1) **Business Activity.** Engage in any business activity except the Business.

(2) **Liens.** Create, incur, assume or suffer to exist, any Lien on TPC's Property, including the Collateral and the Capital Stock of TPC other than Permitted Liens.

(3) **Disposal of Property.** Dispose of any of the Collateral without the prior written consent of Hydro.

(4) **Debt.** Allow, except with the prior consent of Hydro, any Debt to be created, incurred, assumed or suffered to exist, directly or contingently or otherwise, other than:

(a) Debt to Hydro;

(b) unsecured current liabilities incurred and payable in the ordinary course of the Business and not represented by any note, bond or debenture; or

(c) Purchase Money Debt, provided that the payments under such Purchase Money Debt do not exceed, in any one year period, $15,000.

(5) **Mergers.** Reorganize, amalgamate, merge, consolidate or otherwise enter into any form of business combination with any other Person.

(6) **Guarantees and Indemnities.** Guarantee or indemnify or give financial assistance in respect of any contingent liability in respect of any Debt or any other obligations or liabilities of any other Person at any time other than TPC's guarantee of the Debt owed by NCN to Hydro under the NCN Financing Agreement.

(7) **Dividends.**

(a) Declare or pay any dividends or other distributions after Hydro has provided notice to TPC that an Event of Default has occurred; or

(b) Declare or pay any dividends or other distributions, in any other circumstances if, after declaring or paying such Dividends or other distributions, TPC would not be able to meet its Obligations under the Loan Documents.

(8) **Financial Year and Auditors**. Change its Financial Year end or its Auditors

(9) **Change in Constating Documents or Capital Stock.**

(a) Make any change in the constating documents or by-laws of TPC as delivered to Hydro which would:

(i) amend the authorized shares or other equity securities of TPC;

(ii) otherwise be detrimental to the rights or interests of Hydro under any of the Loan Documents.

(b) Issue any Capital Stock in TPC that would cause an Event of Default to occur or that would cause a Change of Control of TPC.

(10) **Material Agreements**. Amend, supplement, terminate or waive, or enter into any forbearance from exercising any rights with respect to, any of the terms of any Material Agreement in a manner which would cause a Material Adverse Business Effect or an Event of Default hereunder.

(11) **Limited Partnership Payments.** Make any payment to the Limited Partnership unless at least thirty (30) calendar days prior to the proposed date TPC intends to make the payment to the Limited Partnership it delivers to Hydro a statutory

declaration signed by a duly authorized officer of TPC (each such statutory declaration a "**Limited Partnership Payment Certification**") which shall certify as to the source of the money to be used to make the proposed payment to the Limited Partnership and shall disclose all material information relating to the money to be used in respect of the proposed payment and shall attach notarized copies of all material documents. Hydro shall have the right to request from TPC, within five (5) calendar days of receipt of the Limited Partnership Payment Certification such additional information and notarized copies of documents relating to the monies to be used in respect of the proposed payment as it may require, acting reasonably, and to receive such written consents and waivers from TPC to obtain additional information and documents from any other Person relating to the monies to be used in respect of the proposed payment as Hydro may request, acting reasonably. Hydro shall be required to confirm in writing within twenty (20) calendar days of receipt of the Limited Partnership Payment Certification whether or not it will accept the Limited Partnership Payment Certification, unless the time period is extended by Hydro, acting reasonably, due to Hydro awaiting receipt of the additional information and documents as it may have requested in connection to the Limited Partnership Payment Certification.

If Hydro accepts the Limited Partnership Payment Certification, TPC shall be permitted to make the proposed payment to the Limited Partnership on the condition it provides to Hydro (with concurrent notice to Hydro of the payment that is made to the Limited Partnership and for greater certainty the payment will under this Agreement be Approved Funds and will form part of TPC's Invested Cash), a statutory declaration signed by a duly authorized officer of TPC certifying there has been no material change to any of the information or documents provided by TPC in the Limited Partnership Payment Certification or obtained by Hydro concerning the monies being paid to the Limited Partnership, including the source of the monies. TPC shall not make the payment without providing the said statutory declaration. Hydro shall be required to accept the Limited Partnership Payment Certification, if Hydro determines, acting reasonably, that the monies being used for the payment fall within the definition of TPC's Own Funds or based on Hydro's analysis of the information disclosed and documents provided or otherwise obtained by Hydro. If based on Hydro's analysis, acting reasonably, Hydro determines that the said monies fall within the definition of TPC's Third Party Funds, then Hydro is entitled, acting reasonably, to reject or accept the Limited Partnership Payment Certification. In making that determination, Hydro will consider the source of the monies, the terms of any financing, any repayment requirements associated with the monies that have been provided, whether or not any Person has recourse against TPC's Units in the event of default in respect of any financing associated with obtaining the monies and, if so, the likelihood of that right being exercised. If Hydro rejects the Limited Partnership Payment Certification, TPC shall not be entitled to proceed with the proposed payment. If Hydro accepts the Limited Partnership's Payment Certification, the payment can be made and the funds will be Approved Funds and once the payment is made, it shall form part of TPC's Invested Cash.

(12) **Change of Control.** There shall be no Change of Control.

(13) **Change of Registered Owner.** Change the registered owner of the Capital Stock of TPC to any person other than the Chief or a Councillor of NCN, as bare trustee for NCN, or change the form of bare trustee declaration prior to obtaining the written consent of Hydro to the change.

10.3 <u>Cross-Default.</u>

Any Event of Default (as defined in the NCN Financing Agreement) by TPC or by NCN shall be deemed to be an Event of Default hereunder.

ARTICLE XI
SECURITY

11.1 Security.

TPC shall execute and deliver the Security Documents to which it is a party, with each of the said Security Documents to be in form and substance satisfactory to Hydro, acting reasonably, as and when required hereunder or under the Loan Documents as continuing collateral security in the Collateral for the due, prompt and complete payment, performance and satisfaction by TPC of all of its indebtedness, liabilities and obligations of every nature whatsoever (whether present or future, direct or indirect, absolute or contingent, matured or unmatured, at any time due or accruing due, wheresoever and howsoever incurred, including any ultimate unpaid balance thereof, in any currency, and whether incurred prior to, at the time of or subsequent to the execution of this Agreement) to Hydro, in connection with this Agreement and the other Loan Documents (collectively, the "**Obligations**").

11.2 Security Documents Prevalence.

Notwithstanding anything to the contrary herein, this Agreement shall be interpreted in all respects having regard for the fact that, and the Security Documents shall provide that, (a) Hydro has a first charge security interest on TPC's Units and the Distributions on TPC's Units and any interest related to TPC's Units and the said Distributions; and (b) Hydro's sole recourse for payment of the Obligations shall be to the Collateral in accordance with the provisions of this Agreement, and for greater certainty, it shall have no right to sue TPC or NCN on any personal covenant to pay all or any of the Obligations. Without limiting the generality of the foregoing, it is agreed, and the Security Documents shall provide that if TPC is in default of the repayment provisions specified in Section 2.5, Hydro's sole recourse for the payment of the Total Outstandings under (and all other amounts owing to Hydro for costs, interest or otherwise in connection with) the Equity Credit Facility on the Maturity Date shall be to TPC's Loan Units and the Distributions thereon.

11.3 Registrations.

Hydro, in its sole discretion, may register, file or record the Liens constituted by the Security Documents in all jurisdictions where such registration, filing, or recording is necessary or of advantage to the creation, perfection, preservation or protection of such Liens.

11.4 Renewals Registrations, Filings, Recordings.

Hydro may renew such registrations, filings and recordings from time to time as and when required or of advantage, in the sole discretion of Hydro, to keep them in full force and effect. TPC acknowledges that the forms of the Security Documents have been prepared based upon the Laws of the jurisdictions indicated therein as being applicable thereto in effect at the date hereof and that such Laws may change. TPC agrees that, following prior notice to and consultation with TPC, upon direction from Hydro, shall have the right to require that the forms of the Security Documents be amended, restated or supplemented, to reflect any changes in such Laws, whether arising as a result of statutory amendments, court decisions or other similar changes, in order to confer upon Hydro the Liens in the Collateral intended to be created by the Security Documents, in the sole discretion of Hydro. For greater certainty, nothing in this Agreement can be used by Hydro or TPC to expand or reduce or otherwise change the scope of the Property comprising the Collateral as defined herein or to confer upon Hydro a right to sue TPC or NCN on a personal covenant to pay all or any of the Obligations, or to require any guarantees, indemnities or covenants from NCN or any other Person in respect of the Obligations or otherwise.

ARTICLE XII
EVENTS OF DEFAULT

12.1 Events of Default.

If any of the following events, conditions or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) TPC shall fail to pay any portion of the principal or interest or any costs or other amounts due hereunder or under any of the other Loan Documents on the date when due hereunder, and such amount remains unpaid for a period of six (6) Business Days after Hydro notifies TPC that the amount is overdue, provided however, that this provision shall be read in conjunction with Section 12.2 and with the provisions in this Agreement and the other Loan Documents which provide that, for so long as no Event of Default has occurred that remains outstanding and uncured, all such payments to Hydro are to be made solely through the irrevocable assignment and direction to Hydro of the Distributions on TPC's Units (or portion thereof, as applicable hereunder) prior to the Maturity Date (and, in certain circumstances hereunder, after the Maturity Date), and from no other source, such that for so long as the Distributions are so assigned and directed and are paid over to Hydro as and when declared by the General Partner of the Limited Partnership pursuant to the irrevocable assignment and direction in favour of Hydro, TPC shall be deemed to be in compliance with its covenants to pay for all purposes hereunder and under the other Loan Documents. The parties hereto acknowledge that neither TPC nor NCN control the timing or amount of such Distributions, and as such, there may be periods of time during which there are no or few Distributions to be paid over to Hydro in accordance with the irrevocable assignment and direction to Hydro, and this shall not be construed to be an Event of Default hereunder;

(b) any representation or warranty or certification made or deemed to be made by TPC pursuant to or in connection with any of the Loan Documents delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(c) TPC shall fail to perform or observe any other term, covenant or agreement contained in any of the Loan Documents on its part to be performed or observed and such failure shall remain unremedied for fifteen (15) Business Days (the "**Cure Period**") after written notice thereof shall have been given to TPC by Hydro; provided that the length of the Cure Period shall be extended by Hydro in its unfettered discretion where TPC demonstrates to Hydro that the breach is not capable of being cured within fifteen (15) Business Days but provides Hydro, within ten (10) Business Days, with a plan for curing the breach within sixty (60) calendar days and in good faith implements such plan;

(d) any of the Loan Documents, at any time, is not or ceases to be valid or enforceable in whole or in part, or if any Lien intended to be created by any of the Security Documents is not or ceases to be a valid and perfected Lien having the ranking or priority contemplated thereby, or if the validity or enforceability of any of the Loan Documents or the validity or perfection of any such Lien shall be contested by any party thereto or any other Person (unless such contestation by such party or other Person is being opposed diligently, in good faith and by proper legal proceedings by Hydro with the assistance of TPC and Hydro covenants to oppose such contestation in good faith where there is a reasonable prospect of success), or if any Person (other than Hydro or the Limited Partnership) obtains any interest in the Collateral or any part thereof (except Permitted Liens); provided however, that this provision shall only be invoked where Hydro, acting reasonably, has determined that its inability to enforce the said Lien with its intended ranking or priority cannot be cured by Hydro within a reasonable period of time or without Hydro being adversely affected notwithstanding that TPC has provided a written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said Lien with its intended ranking or priority;.

(e) with respect to Debt of TPC under any one or more agreements other than the Debt under the Loan Documents,

(i) TPC shall fail to pay any principal, interest or other amount pursuant to the agreements governing such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) when such amount becomes due and payable (whether by scheduled maturity, required repayment, acceleration, demand or otherwise) and such failure shall continue after any applicable grace period specified in such agreement or agreements; or

(ii) any other event, condition or circumstance shall occur and shall continue after any applicable grace period specified in such agreement or agreements, if the effect of such event, condition or circumstance is to accelerate the maturity of such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency); or

(iii) other Debt of TPC in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) shall be declared to be due and payable prior to the stated maturity thereof under any such agreement or agreements;

(f) the occurrence of any default, or any event or condition which, with the giving of notice or passage of time, or both, would constitute a default by TPC under any

Material Agreement, and such default shall continue unremedied after any applicable grace period specified in such Material Agreement;

(g) TPC shall:

(i) become insolvent;

(ii) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(iii) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iv) institute or have instituted against it any proceeding seeking (x) to adjudicate it a bankrupt or insolvent, (y) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors, or (z) the entry of an order for relief or the appointment of a Receiver, interim Receiver, Receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property, and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within forty-five (45) days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a Receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; or

(v) take any corporate action to authorize any of the foregoing actions;

(h) a Notice is sent to or received by TPC from any creditor with respect to the intention of such creditor to enforce a Lien on:

(i) any of the Collateral; or

(ii) any Property of TPC (other than the Collateral) unless such notice is being contested in good faith by appropriate legal proceedings and such notice has not resulted in, or does not involve, any danger of the sale, forfeiture or loss of any of the Collateral;

(i) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Entity which may be reasonably likely to require TPC to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against TPC, and either:

(i) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

(ii) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(j) the audited financial statements of TPC in respect of any Financial Year are qualified in any material adverse respect by the Auditors;

(k) the occurrence of a Change of Control;

(l) the loss, suspension or failure to renew any licence or permit held by TPC or any agreement to which TPC is a party the effect of which would prohibit or otherwise restrict TPC from conducting all or a material part of the Business;

(m) TPC is enjoined or restrained in any material way by an order of any Governmental Entity, arbitrator or board in Canada or elsewhere from conducting all or a material part of the Business;

(n) the occurrence of a Material Adverse Business Effect;

(o) the occurrence of an Event of Default committed by TPC or NCN (as such term is defined in the NCN Financing Agreement); or

(p) the occurrence of any event, condition or circumstance which, with the giving of notice or passage of time, or both, would constitute an Event of Default after the expiration of, in the case of a Loan Document, the applicable Cure Period or in the case of any other agreement, the applicable cure period (if any) thereunder;

then, and in any such event, Hydro shall be entitled by written notice to TPC to: (i) terminate the obligation of Hydro to make further Advances under the Equity Credit Facility; and/or (ii) demand repayment of all indebtedness of TPC to Hydro under the Equity Credit Facility, whereupon the principal amount of all outstanding Advances and other amounts payable thereunder shall become forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by TPC (except such notices as may be required under applicable Laws). Provided, however, that Hydro shall only have recourse to the Collateral for the repayment of the Obligations, and further provided, however, that upon any Event of Default specified in Section 12.1(g), the obligation of Hydro to make Advances hereunder shall automatically terminate.

12.2 **Expenses of Hydro.**

Upon the occurrence of any Event of Default which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Default. All reasonable expenses, costs and charges incurred by or on behalf of Hydro in connection with: (i) any remedial action taken pursuant to this Section; or (ii) the realization of the Collateral, including all reasonable fees, court costs, Receiver's or agent's remuneration and other expenses of taking possession of, repairing, protecting, insuring, preparing for disposition, realizing, collecting, selling, transferring, delivering or obtaining payment of the Collateral, in all cases shall be added to and form a part of the Obligations, but subject always to the provision that Hydro's sole recourse for payment of the Obligations shall be to the Collateral, as set out herein. For greater certainty, for so long as there is no Event of Default hereunder, Section 5.14 of the PDA shall govern the payment of Hydro's costs and expenses properly recoverable hereunder.

12.3 **Remedies Cumulative.**

The remedies provided for in this Agreement and each of the Loan Documents are cumulative and do not exclude any other right or remedy provided by Law (except that there shall be no right of Hydro to sue TPC or NCN on any personal covenant to pay, it being acknowledged that Hydro's sole recourse is to the Collateral).

12.4 **Allocations.**

For greater certainty, the parties agree that any expenses or costs that are, by the terms of this Agreement, reimbursable to Hydro shall be allocated to the Equity Credit Facility.

ARTICLE XIII
PAYMENTS, COMPUTATIONS AND INDEMNITIES

13.1 Timing of TPC Payments.

Unless otherwise expressly provided in this Agreement or agreed to by Hydro, TPC shall make any payment required to be made by it to Hydro by depositing the amount of such payment in Hydro's Account not later than 11:00 a.m. (Winnipeg time) on the date such payment is due.

13.2 Timing of Hydro Payments.

Unless otherwise expressly provided in this Agreement and subject to the provision by Hydro of the requisite notice to TPC and the General Partner as set out in Section 4.2(1), Hydro shall make any Advance or other payment to TPC hereunder by crediting or causing the crediting of the Limited Partnership Account for TPC with the amount of such Advance on the date such Advance is to be made.

13.3 Payments on Non-Business Days.

Whenever any payment hereunder shall be stated to be due on a day other than a Business Day, such payment shall be made on the next succeeding Business Day, and such extension of time shall in such case be included in the computation of interest or fees, as the case may be.

13.4 Overdue Amounts.

All amounts owed by TPC which are not paid when due (whether at stated maturity, on demand, by acceleration or otherwise) shall bear interest (both before and after judgment), from the date on which such amount is due until such amount is paid in full, payable on demand, at a rate per annum equal at all times to the rate in effect on the date the said amounts are due and unpaid.

13.5 Application of Payments, Repayments and Prepayments.

All amounts received by Hydro from or on behalf of TPC, including from realization by Hydro on the Collateral of the Security, and not previously applied pursuant to this Agreement shall be applied:

(a) first, in reduction of TPC's obligation to pay any costs and expenses, which are due and owing to Hydro and reimbursable or indemnity amounts or Losses which have been determined by a court of competent jurisdiction or by arbitration to be due and owing to Hydro;

(b) second, in reduction of TPC's obligation to pay any unpaid interest accrued on the principal amount of Advances;

(c) third, in reduction of TPC's obligation to pay any amounts due and owing on account the principal amount of all Advances; and

(d) fourth, to be held in escrow by Hydro in an interest-bearing account on account, and up to the amount, of any written claim by Hydro then issued and outstanding seeking reimbursement or indemnity hereunder for Losses, pending determination by a court of competent jurisdiction or by arbitration as to the amount (if any) which is due and owing to Hydro hereunder (in which event, such funds and any interest earned thereon shall be dealt with in accordance with the order of the court of competent jurisdiction or arbitrator, as the case may be); and

(e) fifth, to TPC or such other Persons as may lawfully be entitled to the remainder or as any court of competent jurisdiction may otherwise direct.

13.6 Computations of Interest and Fees.

All computations of interest shall be made by Hydro, taking into account the actual number of days occurring in the period for which such interest is payable pursuant to Sections 4.4(a)(i) and on the basis of a year of 365 days, except for interest payable under Sections 4.4(a)(ii) and 4.4(a)(iii), in respect of which the computation of interest shall be made based on a semi-annual interest computation and not by the number of days in the six (6) month period.

Notwithstanding any provision to the contrary contained in this Agreement, in no event shall the aggregate "interest" (as defined in Section 347 of the *Criminal Code* (Canada), as the same may be amended, replaced or re-enacted from time to time) payable under this Agreement exceed the maximum amount of interest on the "credit advanced" (as defined in that Section) under this Agreement lawfully permitted under that Section and, if any payment, collection or demand pursuant to this Agreement in respect of "interest" (as defined in that Section) is determined to be contrary to the provisions of that Section, such payment, collection or demand shall be refunded to TPC. For purposes of this Agreement, the effective annual rate of interest shall be determined in accordance with generally accepted actuarial practices and principles over the term that the Equity Credit Facility is outstanding on the basis of annual compounding of the lawfully permitted rate of interest and, in the event of any dispute, a certificate of a Fellow of the Canadian Institute of Actuaries appointed by Hydro will be conclusive for the purposes of such determination.

Each determination by Hydro of any amount payable hereunder by TPC shall be prima facie evidence of the amount payable for all purposes absent error.

13.7 Indemnity for Change in Circumstances.

If with respect to Hydro:

(a) any change in Law, or any change in the interpretation or application by any Governmental Entity of any Law occurring or becoming effective after the date hereof; or

(b) any compliance by Hydro with any direction or requirement having the force of Law of any Governmental Entity made or becoming effective after the date hereof, in either case shall have the effect of causing Loss to Hydro by:

(i) increasing the actual cost to Hydro of performing its obligations under this Agreement or in respect of any Advance; or

(ii) reducing any amount otherwise properly payable to Hydro under this Agreement or in respect of any Advance by any amount that Hydro deems material acting reasonably (other than pursuant to Section 13.6);

then Hydro may give notice to TPC specifying the nature of the event giving rise to such Loss and TPC shall, within twenty (20) Business Days of demand, pay such amounts as Hydro may specify is necessary to compensate Hydro for such Loss. A certificate as to the amount of any such Loss, submitted in good faith by Hydro to TPC shall be prima facie evidence of the amount of such Loss for all purposes, absent error.

13.8 Taxes on TPC Payments.

Except as required by applicable Law, TPC shall make all payments under this Agreement to Hydro without deducting or withholding of any Taxes. To the extent that deduction or withholding of Taxes is required by applicable Law, TPC will:

(a) promptly notify Hydro of such requirement;

(b) pay to the appropriate authority the full amount required to be so withheld or deducted before penalties attach thereto or interest accrues thereon;

(c) promptly forward to Hydro an official receipt or other documentation reasonably satisfactory to Hydro evidencing such payment to such authority; and

(d) pay to Hydro an additional amount so that Hydro receives the full amount it would have received had no such deduction or withholding been required.

If any Taxes are directly asserted against Hydro with respect to any payment under this Agreement, Hydro may pay such Taxes and TPC shall promptly pay such additional amount (including any penalties, interest and expenses) necessary so that the net amount received by Hydro after the payment of such Taxes, including any Taxes on such additional amounts, shall equal the amount Hydro would have received had Hydro not paid such Taxes.

TPC will indemnify Hydro for all incremental Taxes, interest or penalties that Hydro must pay if TPC fails to deduct or withhold any Taxes when due or to send Hydro the required receipts or other documentation.

Hydro acknowledges that in respect of this Section 13.6(2), Taxes shall not include any income taxes that may be payable by Hydro. Hydro shall remain solely obligated to pay and shall save TPC and NCN harmless from any income taxes that may be asserted against Hydro or payable by Hydro, including with respect to any payments or amounts received or made under this Agreement.

13.9 Indemnity.

TPC hereby agrees to indemnify, exonerate and hold Hydro and its officers, directors, employees, agents and other representatives (in this Section 13.7(1), the "**Indemnified Parties**") free and harmless from and against any and all Claims, demands, actions, causes of action, suits, losses, costs (including all documentary, recording, filing, mortgage duties), charges, liabilities and damages, and expenses in connection therewith (irrespective of whether such Indemnified Party is a party to the action for which such indemnification hereunder is sought), and including reasonable legal fees and disbursements (collectively, in this Section 13.7(1), the "**Indemnified Liabilities**") paid, incurred or suffered by, or asserted against, the Indemnified Parties or any of them or, with respect to, or as a direct or indirect result of: (i) any transaction financed or to be financed in whole or in part, directly or indirectly, with the proceeds of any Advances obtained hereunder; or (ii) the execution, delivery, performance or enforcement of this Agreement or any of the Loan Documents, except for such Indemnified Liabilities that a court of competent jurisdiction determines or rules to be on account of the relevant gross negligence or willful misconduct of the Indemnified Party or any Person for whom such Indemnified Party is responsible at law (in which event, such Party shall indemnify TPC, and its officers and directors, for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct).

13.10 TPC Obligations.

All obligations provided for in this Section 13.7 shall not be reduced or impaired by any investigation made by or on behalf of Hydro. If, for any reason, the obligations of TPC pursuant to this Section 13.7 shall be unenforceable, TPC agrees to make the maximum contribution to the payment and satisfaction of each obligation that is permissible under Law, except to the extent that a court of competent jurisdiction determines such obligations arose on account of the gross negligence or willful misconduct of Hydro or any Person for whom Hydro is responsible at law (in which event such Party shall indemnify TPC, and its officers and directors for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct).

13.11 Contribution.

If any provision in any of the Loan Documents providing for indemnification by TPC (the "**Indemnitor**") in favour of Hydro or any of the Indemnified Parties (as defined in Section 13.7) (the "**Indemnitee**") is found by reason of the occurrence of an event, other than the gross negligence or wilful misconduct of the Indemnitee, to be unenforceable by a court of competent jurisdiction in a final judgment that has become non-appealable, then the Indemnitor shall contribute to the amount paid or payable by the Indemnitee which is subject to the indemnification provision in such proportion as is appropriate to reflect not only the relative benefits received by the Indemnitor on the one hand and the Indemnitee on the other hand but also the relative fault of the Indemnitor and the Indemnitee but only to the extent that such contribution is consistent with the terms of the final judgment. The rights of contribution herein provided shall be in addition to and not in derogation of any other right to contribution which the Indemnitee may have under this Agreement or applicable Laws.

13.12 Market Make-whole Payment

In the event of a voluntary payment of principal by TPC to Hydro prior to the date on which such payment is due and payable (other than any payment of interest or costs whatsoever or any payment out of Distributions, including payments of principal pursuant to any of Sections 2.6(2), 2.6(2) from Distributions on TPC's Units), the principal amount of the repayment shall be an amount calculated by Hydro on the Business Day preceding the date of repayment equal to the applicable Canada Yield Price on the Business Day preceding the date of the payment less the principal amount of the Equity Credit Advances that are being repaid. For greater certainty, if the amount so determined is a positive number it shall increase the principal amount to be repaid by that amount, and if it is a negative number it shall reduce the principal amount to be repaid by that amount.

13.13 Confirmation of Limited Recourse.

For greater certainty, Hydro acknowledges that nothing in this Article XIII shall in any way detract from the limited recourse nature of Hydro's security and remedies hereunder, as set out in Section 11.1 of this Agreement.

ARTICLE XIV
DISPUTE RESOLUTION

14.1 Dispute Resolution.

Each of the parties to this Agreement agrees that any disputes or claims arising out of this Agreement shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the PDA and it shall not bring any action in respect of any matter arising hereunder, other than pursuant to Article XXI of the PDA, against any other party.

ARTICLE XV
GENERAL PROVISIONS

15.1 Notices.

All notices provided for in this Agreement or in the other Loan Documents shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule F hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

Each Borrowing Notice and Repayment Notice shall be irrevocable and binding on TPC.

15.2 Time of the Essence.

Time shall be of the essence of this Agreement.

15.3 Third Party Beneficiaries.

Each party hereto intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any Person, other than the parties hereto and the Persons contemplated in Section 13.7 or Section 15.7, and no Person, other than the parties hereto and the Persons contemplated in Section 13.7 or Section 15.7, shall be entitled to rely on the provisions hereof in any action, suit, proceeding, hearing or other forum. For greater certainty, nothing in this Section 15.3 is intended to prevent or restrict the Taskinigaph Trust from receiving Dividends declared by the Board of Directors of TPC pursuant to the NCN Deed of Assignment subject always to TPC's compliance with the covenants, representations and warranties of this Agreement.

15.4 Enurement.

his Agreement shall enure to the benefit of and be binding upon the Parties . This Agreement shall be binding upon any assigns and enure to the benefit of any permitted assigns.

15.5 Counterparts.

Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

15.6 Knowledge.

Where any representation or warranty contained in this Agreement or any other Loan Documents is expressly qualified by reference to the "best of the knowledge" of TPC, or where any other reference is made herein or in any Loan Document to "the knowledge" of TPC, it shall be deemed to refer to the best of the knowledge of the members of the Board of Directors of TPC.

15.7 Assignment.

Neither this Agreement nor the rights and obligations under this Agreement shall be assignable or transferable by TPC or Hydro, except that Hydro may assign this Agreement to any Affiliate, on the condition that notwithstanding the assignment, Hydro will remain jointly and severally liable with the said Affiliate, for compliance with the covenants of Hydro under this Agreement.

15.8 Non-Merger.

Except as otherwise expressly provided in this Agreement, the covenants, representations and warranties of the Parties in this Agreement and the Loan Documents shall not merge on and shall survive the Initial Closing, the Final Closing and the Final Investment Closing and the making of any Advance, and notwithstanding such Initial Closing and Final Closing and the Final Investment or Advance, or any investigation made by or on behalf of any party, shall continue in full force and effect. Neither the Initial Closing, the Final Closing or the Final Investment Closing nor the making of any Advance shall prejudice any right of one party against any other party in respect of anything done or omitted hereunder or under any of the other Loan Documents or in respect of any right to damages or other remedies.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, on the date first above written.

TASKINIGAHP POWER CORPORATION

Per:
Name:
Title: President

Per:
Name:
Title: Vice- President

Per: ______________________________
Name: Shirley L. Linklater
Title: Secretary-Treasurer

THE MANITOBA HYDRO-ELECTRIC BOARD

Per:
Name: Title: President and Chief Executive Officer

Per:
Name: Title: Assistant Corporate Secretary

SCHEDULE A

REPAYMENT NOTICE

TO: THE MANITOBA HYDRO-ELECTRIC BOARD ("Hydro")

FROM: TASKINIGAHP POWER CORPORATION ("TPC")

This Repayment Notice is delivered to you pursuant to Section 4.6 of the financing agreement (the "TPC Financing Agreement") dated •, 2015 between TPC, as borrower, and Hydro, as lender. All capitalized terms used in this Repayment Notice and defined in the TPC Financing Agreement shall have the meanings defined in the TPC Financing Agreement.

1. TPC hereby gives notice of repayment as follows:

   (a) Date of repayment:

   (b) Type of Advance:

   (c) Amount of principal being repaid:

TASKINIGAHP POWER CORPORATION

Per:
Name:
Title:

Per:
Name:
Title:

SCHEDULE B

[intentionally blank]

SCHEDULE C

ISSUED AND OUTSTANDING CAPITAL STOCK AND DEBT

To be provided on Final Investment Date

SCHEDULE D

MATERIAL AGREEMENTS

Provided on Initial Closing

SCHEDULE E

LIABILITIES

Provided on Initial Closing

SCHEDULE F

ADDRESS FOR NOTICE

Taskinigahp Power Corporation
Attention: President
General Delivery
Nelson House, MB R0B 1A0
Fax: (204) 484-2392

Manitoba Hydro
Attention: General Counsel
360 Portage Avenue
Winnipeg, MB R3C 0G8
Fax: (204) 360-4947

SCHEDULE G

LIST OF SECURITY DOCUMENTS

1. TPC Security Agreement
2. Pledge of TPC's Units
3. Limited Power of Attorney granted by TPC respecting TPC's Units

SCHEDULE H

AUTHORIZATIONS – HYDRO

1. Order in Council as required pursuant to the provisions of the Hydro Act.

2. Such Additional Borrowing Authorizations required from time to time.

SCHEDULE 8.1
SECOND AMENDED AND RESTATED LIMITED PARTNERSHIP AGREEMENT

SECOND AMENDED AND RESTATED LIMITED PARTNERSHIP AGREEMENT

between

5022649 MANITOBA LTD.,

- and -

TASKINIGAHP POWER CORPORATION,

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD.

DATED as of March 31, 2015

TABLE OF CONTENTS

SECOND AMENDED AND RESTATED LIMITED PARTNERSHIP AGREEMENT

This Agreement made as of the 31st day of March, 2015.

BETWEEN:

5022649 MANITOBA LTD.,

(hereinafter called the "**General Partner**"),

OF THE FIRST PART,

- and -

TASKINIGAHP POWER CORPORATION,

(hereinafter called "**Taskinigahp Power Corporation**"),

OF THE SECOND PART

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter called "**Hydro**"),

OF THE THIRD PART.

WHEREAS the **General Partner** was incorporated under the laws of the Province of Manitoba on November 30, 2004;

AND WHEREAS a partnership agreement (the "**Initial Agreement**") was entered into on the 9th day of December, 2004, between the **General Partner** and the **Initial Limited Partner**;

AND WHEREAS under the **Initial Agreement**, the **General Partner** and the **Initial Limited Partner** formed a partnership known as the Wuskwatim Power Limited Partnership (the "**Partnership**") which was registered in accordance with the laws of the Province of Manitoba as a limited partnership on the 9th day of December 2004;

AND WHEREAS the **Initial Agreement** was amended and restated pursuant to an agreement dated the 28th day of June, 2006 between the **General Partner**, **Taskinigahp Power Corporation** and **Hydro ("First Amended and Restated Agreement")**;

NOW THEREFORE in consideration of the premises herein contained and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE I

GENERAL INTERPRETATION

Definitions

1.01 For the purpose of this Agreement, the following terms shall be deemed to have the following meanings:

(a) "**Act**" means *The Partnership Act* (Manitoba);

(b) "**Affiliate**" has the meaning ascribed to affiliate or associate as those terms are defined in *The Securities Act* (Manitoba);

(c) "**Agreement**" means this Amended and Restated Limited Partnership Agreement and any amendments or modifications made thereto, including without limitation any schedules or appendices attached hereto;

(d) "**Allowable Operating Expenses**" means all expenses incurred directly or indirectly by the **General Partner** in managing the **Business** of the **Partnership**, including, without limiting the type of expenses, all administrative expenses, including the costs of holding meetings of the board of directors of the **General Partner** and preparing financial statements of the **General Partner** but, for greater certainty, shall not include any costs other than costs incurred in furtherance of the **Business** or which are properly allocated, in whole or in part, to the **Business**, and, without limiting the generality of the foregoing, shall not include any of the costs incurred by **Hydro** in building the project known as the Churchill River Diversion nor any of the costs incurred by **Hydro** and allocated to the operation of the project known as the Churchill River Diversion;

(e) "**Business**" shall have the meaning ascribed to it in section 2.05 hereof;

(f) "**Capital Contribution**" means, with respect to a **Partner**, the amount in cash or other property contributed to the **Partnership** by such **Partner**;

(g) "**Construction Agreement**" means the agreement to be entered into by the **Partnership** as owner and **Hydro** as project manager in substantially the same form as described in the **PDA**;

(h) "**Declaration**" means the declaration pursuant to the Act to be filed under *The Business Names Registration Act* of Manitoba;

(i) "**Debt Ratio**" means for any particular day, the quotient of the Limited Partnership's Net Debt (as defined in the Project Financing Agreement) on such day divided by the sum of: (i) the Limited Partnership's Net Debt on such day; and (ii) the Limited Partnership's Equity (as defined in the Project Financing Agreement) on such day, expressed as a percentage;

(j) "**Distributable Cash**" in respect of any distribution period, means **EBITDA** earned by the **Partnership** for such period, plus any additional cash on hand at the end of a distribution period and any additional amounts that the **General Partner** approves for distribution, less: (i) payments to satisfy debt service obligations (including principal, interest and deposits for debt retirement) incurred in such period under credit facilities of the **Partnership** (including under the **Project Financing Agreement**) or other agreements to which the **Partnership** is bound; (ii) payments to satisfy general and administrative expenses and other known expense obligations of the **Partnership**; and (iii) amounts retained in respect of the distribution period to cover (1) anticipated expenses, (2) reserves under section 6.06 of this **Agreement** and (3) the amount (if any) required to be held as equity in order to maintain the **Debt Ratio** in accordance with section 6.05;

(k) "**EBITDA**" for any period means earnings before interest, income taxes, depreciation and amortization, determined in accordance with **Generally Accepted Accounting Principles** ("earnings" for this purpose means the **Net Income** or **Net Loss**, as applicable, for that period);

(l) "**Final Closing Date**" has the meaning ascribed thereto in the **PDA**;

(m) "**Financial Statements**" shall mean the audited financial statements of the **Partnership** prepared in accordance with **Generally Accepted Accounting Principles**;

(n) "**Fiscal Year**" means the fiscal year of the **Partnership** as described in section 2.04;

(o) "**General Partner**" shall mean 5022649 Manitoba Ltd. or any other **Person** who may become the general partner of the **Partnership** in place of or substitution for 5022649 Manitoba Ltd. and is deemed to be the **General Partner** from time to time under the terms of this **Agreement**;

(p) "**Generally Accepted Accounting Principles**" means, at any time, accounting principles as recommended by the Canadian Institute of Chartered Accountants, or any successor **Person** at such time;

(q) "**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by The Manitoba Hydro Act, R.S.M. 1987, c.H190;

(r) "**Hydro Service Agreements**" means, collectively, the Management Agreement, the Project Financing Agreement, the Construction Agreement, the Power Purchase Agreement, the Operations and Maintenance Agreement, the Interconnection and Operating Agreement and the System Operations and Dispatch Agreement;

(s) "**Initial Agreement**" means the Limited Partnership Agreement between the **General Partner** and the **Initial Limited Partner** signed December 9, 2004;

(t) "**Initial Limited Partner**" means **Hydro**;

(u) "**Integrated Power System**" means **Hydro's** integrated system of hydraulic and thermal electric generation and power transmission facilities owned and operated by **Hydro** or in some circumstances, owned by **Hydro** in partnership with others, which system is interconnected with other power utilities. The **Wuskwatim Project** will be part of the **Integrated Power System**.

(v) "**Interconnection and Operating Agreement**" means the agreement entered into between **Hydro** (Transmission and Distribution Business Unit) and **Hydro** (Power Supply Business Unit) dated May 4, 2005, as amended, and to be subsequently assigned by **Hydro** (Power Supply Business Unit) to the **Limited Partnership**, whereby the **Wuskwatim Project** will be interconnected with the **Integrated Power System**;

(w) "**Limited Partner**" shall mean **Hydro** or **Taskinigahp Power Corporation** for so long as each is a holder of at least one **Unit**;

(x) "**Limited Partnership**" or "**Partnership**" means the Wuskwatim Power Limited Partnership formed pursuant to the **Initial Agreement**, as amended and restated by this **Agreement**, for the purpose of the **Business**;

(y) "**Management Agreement**" means the agreement entered into between the **Partnership** as owner and **Hydro** as contractor in substantially the same form as described in the **PDA**;

(z) "**NCN**" means the Nisichawayasihk Cree Nation;

(aa) "**NCN Adverse Effects Agreement**" means the agreement to be entered into by the **General Partner** on behalf of the **Partnership** and **NCN** and **Hydro** in substantially the same form as described in the **PDA**;

(bb) "**NCN Financing Agreement**" means the agreement to be entered into between **NCN, Taskinigahp Power Corporation** and **Hydro** in substantially the same form as described in the **PDA**;

(cc) "**Net Income**" or "**Net Loss**" in respect of any **Fiscal Year** means, respectively, the income or loss of the **Partnership** for such period determined in accordance with Section 6.07;

(dd) "**Operations and Maintenance Agreement**" means the agreement to be entered into between the **Partnership** as owner and **Hydro** as contractor in substantially the same form as described in the **PDA**;

(ee) "**Ordinary Resolution**" means a resolution passed by **Partners** holding, in the aggregate, a majority of the issued and outstanding **Units**, who, being entitled to do so, vote in person or by proxy at a duly convened meeting of **Partners** or any adjournment thereof or, alternatively, pass such a resolution unanimously in writing in lieu of a meeting;

(ff) "**Partner**" means the **General Partner** or any **Limited Partner** and "**Partners**" means all **Limited Partners** together with the **General Partner**;

(gg) "**Partnership Assets**" means all assets and property, whether tangible or intangible and whether real, personal or mixed, at any time owned legally or beneficially by the **Partnership**;

(hh) "**Person**" means and includes any individual, corporation, partnership, firm, trust or any other form of entity or organization;

(ii) "**Power Purchase Agreement**" means the agreement to be entered into between the **Partnership** as owner and **Hydro** in substantially the same form as described in the **PDA;**

(jj) "**PDA**" means the project development agreement entered into by **Hydro**, **NCN**, **Taskinigahp Power Corporation,** the **General Partner** and the **Partnership** regarding the planning, development and construction of the **Wuskwatim Project** and the operation of the **Business**;

(kk) "**Project Financing Agreement**" means the agreement to be entered into between the **Partnership** and **Hydro** in substantially the same form as described in the **PDA**;

(ll) "**Record of Limited Partners**" means the record required to be maintained by the **General Partner** at the principal place of business of the **Partnership** pursuant to The Business Names Registration Act, C.C.S.M. c. B110;

(mm) "**Refinancing**" means any borrowings made by the **Partnership** for any purpose other than operating purposes, which are secured by a mortgage or other charge on or against the **Partnership's** interest in the **Partnership Assets**;

(nn) "**Refinancing Proceeds**" means the net proceeds resulting from a **Refinancing**;

(oo) "**Registrar and Transfer Agent**" means the **General Partner** or an agent appointed thereby to keep a register of **Limited Partners** and a register of the transfer of **Units**;

(pp) "**Sale**" means the disposition of all or any part of the **Partnership Assets**, whether by way of sale, expropriation or otherwise;

(qq) "**Sale Proceeds**" means:

i) the proceeds resulting from a **Sale**, after deducting the amounts required to discharge or partially discharge any security relating thereto, and/or repay or partially repay loans incurred in respect of the acquisition of any asset of the **Partnership** for which the **Sale Proceeds** are received and all costs incurred as a result of such **Sale**; and

ii) the proceeds of any insurance to the extent not applied to repair, rebuild or replace some or all of the assets held by the **Partnership**;

(rr) "**Special Resolution**" means:

i) a resolution approved by all of the votes cast in person or by proxy at a duly constituted meeting of **Partners** who are entitled to vote or at any adjournment of that meeting, called in accordance with this Agreement; or

ii) a written resolution in one or more counterparts signed by Partners holding in the aggregate all of the **Units** held by those **Partners** who are entitled to vote on that resolution at a meeting;

(ss) "**Subscription Agreement**" means the subscription form and power of attorney attached hereto as Schedule "A", or as determined by the **General Partner** pursuant to section 5.04 of this **Agreement**;

(tt) "**Subscription Price**" means the price per **Unit** payable by a **Person** to purchase a **Unit** as set forth in section 5.04 of this **Agreement**;

(uu) "**System Operations and Dispatch Agreement**" means the agreement to be entered into between the **Partnership** and **Hydro** in substantially the same form as described in the **PDA**;

(vv) "**Taskinigahp Power Corporation Financing Agreement**" means the agreement to be entered into between **Taskinigahp Power Corporation** as borrower and **Hydro** as lender in substantially the same form as described in the **PDA**, in which it is defined as the TPC Financing Agreement;

(ww) "**Tax Act**" means the *Income Tax Act* (Canada) as amended from time to time;

(xx) "**Taxable Income**" and "**Tax Loss**", in respect of any tax year means, respectively, the amount of income or loss of the **Partnership** for such period determined in accordance with the provisions of the **Tax Act** (including the amount of taxable capital gains or allowable capital losses, recapture of capital cost allowance or terminal loss, resulting from the disposition of each capital property of the **Partnership** as determined by the **General Partner** in accordance with the provisions of the **Tax Act**);

(yy) "**Term**" has the meaning ascribed thereto in section 2.07 hereof;

(zz) "**Unit**" means one of the units of the **Partnership** representing an interest in the **Partnership** and "**Units**" means all of the units of the **Partnership**;

(aaa) "**Unit Certificate**" means the form of certificate issued by the **Limited Partnership** evidencing the number of **Units** owned by a **Partner** or any certificates issued in replacement thereof in accordance with the provisions of this **Agreement**;

(bbb) "**Wuskwatim Generating Station**" means the proposed hydro-electric generating station forming the **Wuskwatim Project** and consisting of a complex of structures, including the powerhouse, spillway, dam, dyke and transition structures, used in the production of electricity;

(ccc) "**Wuskwatim Project**" means the **Wuskwatim Generating Station** and all related works, excluding the **Wuskwatim Project Related Transmission Facilities**, but including, without limitation, all dams, dykes, channels, control structures, excavations, camps, storage areas, local roads and access road, to be located at Taskinigup Falls near Wuskwatim Lake which, if built, will contribute about 200 megawatts to the **Integrated Power System** through the **Wuskwatim Project Related Transmission Facilities**;

(ddd) "**Wuskwatim Project Related Transmission Facilities**" means the proposed complex of transmission and communication related facilities to be constructed as part of the **Wuskwatim Transmission Project**, including without limitation all transmission lines, switching and transformer stations and the construction power line;

(eee) "**Wuskwatim Transmission Project**" means **Hydro's** proposed project to develop the **Wuskwatim Project Related Transmission Facilities** and all related works.

Interpretation

1.02 For all purposes of this **Agreement** except as otherwise expressly provided or unless the context otherwise requires:

(a) headings are for convenience of reference only and do not form a part of this **Agreement**, nor are they intended to interpret, define or limit the scope, extent or intent of this **Agreement** or any provision hereof;

(b) all references to currency herein are references to Canadian currency unless otherwise stated;

(c) any reference to a statute shall include and shall be deemed to be a reference to such statute and the regulations made pursuant thereto, with amendments made thereto in force from time to time and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute so referred to or the regulations made pursuant thereto;

(d) any reference to any entity shall include and shall be deemed to be a reference to any entity that is a successor to such entity;

(e) words importing the masculine gender include the feminine or neuter gender and words importing the singular include the plural and vice versa;

(f) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(g) all accounting terms not specifically defined herein shall be construed in accordance with **Generally Accepted Accounting Principles**.

ARTICLE II

THE PARTNERSHIP

Continuation of Partnership

2.01 The **General Partner** and the **Limited Partners** acknowledge and confirm that the **Partnership** was formed pursuant to the **Initial Agreement** and that this **Agreement** is an amendment to and a restatement of the terms of the **Initial Agreement**. The **General Partner** and the **Limited Partners** agree to continue the **Partnership** under the laws of the Province of Manitoba and the **General Partner** agrees to prepare, complete and file the requisite "Change in a Limited Partnership Form" required pursuant to The Business Names Registration Act, C.C.S.M. c. B110 and to do all things and to execute and deliver all such documents, instruments and assurances as may be necessary to qualify, continue and keep in good standing the **Partnership** as a limited partnership. The **General Partner** shall take all necessary actions on the basis of information available to it in order to maintain the status of the **Partnership** as a limited partnership.

Name of the Partnership

2.02 The **Partnership** shall carry on business under the name "Wuskwatim Power Limited Partnership" (or such other name or names as the **General Partner** may from time to time adopt if required to comply with laws of the jurisdictions in which the **Partnership** may conduct business). The **General Partner** shall notify each **Limited Partner** of any change in the name of the **Partnership** within 10 days of such change. The **General Partner** shall hold the **Partnership** out as an entity separate from any other **Person**.

Maintaining Status of Partnership

2.03 The **General Partner** shall be the sole general partner of the **Partnership**, and shall do all things and shall cause to be executed, amended and filed such certificates, declarations, registers, instruments and documents as may be required to reflect the constitution of the **Partnership** and to carry on the **Business** of the **Partnership**, including, without limitation, the maintaining of a **Record of Limited Partners** stating for each **Limited Partner** the information prescribed by The Business

Names Registration Act, C.C.S.M. c. B110. The **General Partner** and each **Limited Partner** shall execute and deliver as promptly as possible any document that may be necessary or desirable to accomplish the purposes of this **Agreement** or to give effect to the formation and continuation of the **Partnership** under any and all applicable laws. The **General Partner** shall take all necessary action to reflect the constitution of the **Partnership**, on the basis of information available to it, in order to maintain the status of the **Partnership** as a limited partnership under the laws of the Province of Manitoba and to maintain the **Partnership** in compliance with the laws of any other governing authority having jurisdiction over the **Partnership**. The **General Partner** covenants and agrees that:

i) The **Partnership** will not carry on any business in any jurisdiction unless the **General Partner** has taken all steps which may be required by the laws of that jurisdiction for the **Limited Partners** to benefit from limited liability to the same extent that **Limited Partners** enjoy limited liability under the **Act**. The **Partnership** will not carry on business in any jurisdiction in which the laws do not recognize the liability of the **Limited Partners** to be limited unless, in the opinion of the **General Partner**, the risks associated with the possible absence of limited liability in that jurisdiction are not significant considering the relevant circumstances.

ii) The **Partnership** will carry on business in a manner so as to ensure to the greatest extent possible the limited liability of the **Limited Partners**, and the **General Partner** will register the **Partnership** in other jurisdictions where the **General Partner** considers it appropriate to do so.

Fiscal Year

2.04 The **Fiscal Year** of the **Partnership** shall begin on the 1st day of April and shall end on the 31st day of March in each and every year or on such other date as the **Limited Partners** may determine by **Ordinary Resolution**.

Business of the Partnership

2.05 The business of the **Partnership** (the "**Business**") is the completion of the planning, construction, ownership, maintenance and operation of the **Wuskwatim Project** and the sale of energy generated by it and any activities incidental or related thereto with a view to making a profit therefrom.

Registered Office and Mailing Address

2.06 The registered office and mailing address of the **Partnership** and the registered office and mailing address of the **General Partner** shall be**360 Portage Avenue, Winnipeg, MB R3C 0G8.** The **General Partner** may not change the registered office or mailing address of the **Partnership** without the consent of all **Limited Partners**.

Term

2.07 The term of the **Agreement** (the "**Term**") shall be indefinite, unless the **Partnership** is dissolved in accordance with Article 10. For greater certainty, this **Agreement** is intended to preclude any **Partner** from dissolving the **Partnership** by giving notice to the other **Partners**, except in accordance with the provisions of Article 10.

Representations and Warranties of the General Partner

2.08 The **General Partner** represents and warrants to, and covenants with, each **Limited Partner** that:

(a) the **Partnership** is a valid limited partnership, duly formed under the laws of the Province of Manitoba;

(b) it is and shall continue to be a corporation incorporated and in good standing under the laws of the Province of Manitoba, or any other jurisdiction under which the **General Partner** may continue or under which a successor to the **General Partner** may be incorporated or continue;

(c) it will maintain all registrations in any jurisdiction where the **Business** of the **Partnership** requires such registration necessary for the conduct of the **Business** and, subject to the successful completion of all necessary regulatory reviews, will have and will continue to have all licenses and permits necessary to carry on the **Business** as **General Partner**;

(d) it has and will continue to have the capacity and corporate authority to act as the general partner of the **Partnership** and to perform its obligations under this **Agreement**, and such obligations do not and will not conflict with, nor do they or will they result in a breach of, its articles of incorporation, its by-laws, any resolutions of its directors or shareholders or any agreement to which it is a party or by which it is bound;

(e) the entering into of this **Agreement** by the **General Partner**, and the performance of its obligations under this **Agreement**, do not and will not require the approval or consent of, or any notice to or filing with, any governmental authority except such approvals and consents as: (i) have been obtained on or before the date hereof; or (ii) will be obtained by the **General Partner** prior to such consents and approvals being required in order for the **General Partner** to carry out its duties and covenants hereunder;

(f) it is not, and shall continue not to be, a non-resident of Canada within the meaning of the **Tax Act**;

(g) the **General Partner** has taken and will take all necessary corporate action to authorize the execution, delivery and performance of this **Agreement**, and this **Agreement** constitutes a valid and binding obligation of the **General Partner**, enforceable against the **General Partner** in accordance with the terms of this **Agreement**;

(h) no authorization, consent or approval of, or filing with, or notice to, any **Person** is required in connection with the execution, delivery or performance of this **Agreement** by the **General Partner,** except such authorizations, consents and approvals as: (i) have been obtained on or before the date hereof; or (ii) will be obtained prior to such authorizations, consents and approvals being required in order for the **General Partner** to carry out its duties and covenants hereunder;

(i) there are no actions, suits or proceedings pending or, to the knowledge of the **General Partner**, threatened, against or affecting the **General Partner** or any of its assets or undertaking at law or in equity or before any arbitrator or any governmental authority having jurisdiction which, if determined adversely, could affect adversely the **General Partner**, and the **General Partner** is not in default with respect to any law, regulation, order, writ, judgment, injunction or award of any competent governmental authority, court, arbitrator or instrumentality which would have such an effect.

Representations and Warranties of each Limited Partner

2.09 Each **Limited Partner** represents and warrants to each other **Limited Partner** and to the **General Partner** that it:

(a) is not and shall continue not to be a "non-resident" of Canada within the meaning of the **Tax Act**;

(b) is not and shall not become a "non-Canadian" within the meaning of the Investment Canada Act (Canada);

(c) is legally competent to execute this **Agreement** and all other agreements contemplated hereby and to take all actions required pursuant hereto, and further certifies that all necessary approvals of directors, shareholders, partners, members or otherwise have been given;

(d) shall promptly provide such evidence of its status as the **General Partner** may reasonably request; and

(e) is and shall continue to be a corporation incorporated and in good standing under its jurisdiction of incorporation, which is Manitoba in the case of **Hydro** and **Taskinigahp Power Corporation**.

Covenant on Representations and Warranties

2.10 Each **Limited Partner** covenants and agrees that it will not transfer or purport to transfer its **Units** to any **Person** which would be unable to make the representations and warranties in section 2.09 and will not change its status such that the above representations would at any time be untrue.

Compliance with Laws

2.11 Each **Limited Partner** shall, on request by the **General Partner**, immediately execute all certificates, declarations, instruments and documents necessary to comply with any applicable law or regulation in regard to the formation, continuance, operation or dissolution of the **Partnership** or in connection with the qualification of the **Partnership** to carry on the **Business** or to own the **Partnership Assets**.

Limitation on the Authority of Limited Partners

2.12 No **Partner**, other than the **General Partner**, shall or shall be entitled to:

(a) take part in the management of the **Business** or the **Partnership** or exercise any power in connection with that control or management or transact business on behalf of the **Partnership**;

(b) execute any document, other than those signed in connection with the **Partners** voting on a resolution of the **Partners**, which binds or purports to bind any other **Partner**, the **General Partner** or the **Partnership**;

(c) hold itself out as having the authority or power to bind any other **Partner**, the **General Partner** or the **Partnership**;

(d) have any authority or power to act for or undertake any obligation or responsibility on behalf of any other **Partner, General Partner** or the **Partnership**;

(e) bring any action for partition or sale or otherwise in connection with the **Partnership**, or any interest in any property of the **Partnership**, whether real, tangible or intangible, or file or register or permit to be filed, registered or remain undischarged any lien or charge in respect of any property of the **Partnership**;

(f) compel or seek a partition or sale, judicial or otherwise, of any of the assets of the **Partnership** distributed or to be distributed to the **Partners** in kind in accordance with this **Agreement**;

(g) bring any action for the dissolution of the **Partnership**; or

(h) take any action that will jeopardize or eliminate the status of the **Partnership** as a limited partnership or a "Canadian partnership" for the purposes of the **Tax Act**.

Authority of Hydro

2.13 Notwithstanding the provisions of section 2.12 or any other provision of this **Agreement,** but subject always to the receipt of such approvals as may be required under the **PDA** for **Hydro** or any **Affiliate** of **Hydro** to enter into any agreements with the **Partnership** other than the **Hydro Service Agreements**, **Hydro** shall be entitled to perform all acts and do all things necessary or desirable pursuant to the terms of any agreement between **Hydro** and the **Partnership,** including the **Hydro Service Agreements,** provided, however, that no such act or thing shall jeopardize or eliminate the status of the **Partnership** as a limited partnership or a "Canadian partnership" for the purposes of the **Tax Act**.

ARTICLE III

MANAGEMENT OF PARTNERSHIP

Authority of General Partner

3.01 The **General Partner**, subject to the terms of this **Agreement** and to all applicable laws, shall and is authorized to carry on the **Business** of the **Partnership**, with full power and authority to administer, manage, control and operate the **Business** of the **Partnership** and shall and is given all power and authority to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document necessary for and incidental to carrying on the **Business** of the **Partnership** for and on behalf of and in the name of the **Partnership**. The **General Partner** shall have unlimited liability for the debts, liabilities, obligations and losses of the **Partnership** to the extent that they exceed the assets of the **Partnership**, as required by the **Act**.

Powers of General Partner

3.02 Without limiting the generality of section 3.01 and subject to the terms of this **Agreement**, the **General Partner**, acting reasonably, shall carry out the objects, purposes and all of the activities of the **Partnership** and shall manage the **Business** of the **Partnership** and shall have full power and authority for and on behalf of and in the name of the **Partnership** to:

(a) provide overall management, financial and business planning as required in the operation of the **Business**;

(b) negotiate, execute and perform all agreements which require execution by or on behalf of the **Partnership** involving matters or transactions with respect to the **Business**;

(c) subject to any prior approval of the **Limited Partners** required pursuant to the terms of this **Agreement**, cause the **Partnership** to acquire, sell, transfer or otherwise dispose of, mortgage, pledge, encumber, hypothecate or exchange any or all of the **Partnership Assets**;

(d) use the **Partnership Assets** (including, without limitation, cash on hand) for the purpose of furthering the **Business** on such terms as it sees fit, including, without limitation, the financing of the **Business**, the repayment of obligations of the **Partnership**, the conduct of the **Business** and the purchase or acquisition, as

Partnership Assets, of any other assets or interests in properties, as may be deemed appropriate in its sole discretion in connection with the **Partnership's** operations;

(e) open and manage bank accounts in the name of the **Partnership** and spend the capital of the **Partnership** in the exercise of any right or power exercisable by the **General Partner** hereunder;

(f) borrow funds in the name of the **Partnership** from time to time, including without limitation from the **General Partner** or any affiliate of the **General Partner** provided that the rate of interest and any other expenses relative to those borrowings will not, under any circumstances, exceed that which the Partnership could obtain from a Canadian chartered bank with respect to similar borrowings;

(g) draw, make, execute and issue promissory notes, evidences of indebtedness and all other negotiable or non-negotiable instruments;

(h) mortgage, charge, assign, hypothecate, pledge or otherwise create a security interest in all **Partnership Assets**;

(i) subject to section 6.06, establish such reserves as shall be determined to be reasonable in connection with the operation and future needs of the **Business** in order to carry on prudently the **Business**;

(j) see to the sound management of the **Partnership** and to manage, control and develop all the activities of the **Partnership** and take all measures necessary or appropriate for the **Business** of the **Partnership** or ancillary thereto;

(k) maintain, improve, upgrade, expand, acquire or dispose of the **Partnership Assets** from time to time;

(l) incur and pay all costs and expenses in connection with the **Partnership**;

(m) allocate **Net Income** or **Net Losses** and distribute **Distributable Cash** to the **Partners** in accordance with the provisions of this **Agreement**;

(n) employ, retain, engage or dismiss from employment, individuals, agents, representatives or professionals or other persons with the powers and duties upon the terms and for the compensation as in the discretion of the **General Partner** may be necessary or advisable in the carrying on of the **Business**;

(o) engage agents to assist the **General Partner** to carry out its management obligations to the **Partnership** or subcontract administrative functions;

(p) establish advisory committees to provide to it such advice on such matters as it deems appropriate from time to time;

(q) invest cash assets of the **Partnership** that are not immediately required for the **Business** in investments which the **General Partner** considers appropriate;

(r) act as attorney in fact or agent of the **Partnership** in disbursing and collecting moneys for the **Partnership** and in paying debts and fulfilling the obligations of the **Partnership** and handling and settling any claims of the **Partnership**;

(s) commence or defend any action or proceeding in connection with the **Partnership**;

(t) file returns or other documents required by any governmental or like authority;

(u) make any election that may be made under the **Tax Act** or any other legislation;

(v) purchase, lease or otherwise acquire equipment and premises in connection with the **Business**;

(w) retain legal counsel, experts, advisors or consultants as the **General Partner** considers appropriate and rely upon the advice of such persons;

(x) purchase policies of insurance, as it considers appropriate, for the **Business** and to insure against any liabilities or potential liabilities of the **General Partner**, **Limited Partners** and the **Partnership** that arise or may arise from this **Agreement** or in law or in equity, including, without limiting the generality of the foregoing, relating to personal injury or property damage;

(y) execute and carry out the obligations of the **Limited Partnership** under the terms of the **PDA** and in such other agreements as are referred to in the **PDA** or as are otherwise necessary or desirable for the carrying on of the **Business**;

(z) do anything that is in furtherance of or incidental to the **Business** or that is provided for in this **Agreement** and execute, acknowledge and deliver the documents necessary to effectuate any or all of the foregoing or otherwise in connection with the **Business**; and

(aa) conduct business so that no **Persons** dealing with the **Partnership** will be required to enquire into the authority of the **General Partner** to do any act, take any proceeding, make any decision or execute and deliver any instrument, deed, agreement or document for or on behalf of or in the name of the **Partnership**. The **General Partner** will make all reasonable efforts to insert, and to cause agents of the **Partnership** to insert, the following clause in any contracts or agreements to which the **Partnership** is a party or by which it is bound (other than the **PDA**, the **Interconnection and Operating Agreement** and the **NCN Adverse Effects Agreement** provided that this exclusion from the requirement of inserting the following clause in these agreements shall not be construed as detracting from the limited liability of the **Limited Partners** hereunder or thereunder):

"The parties hereto acknowledge that Wuskwatim Power Limited Partnership is a limited partnership formed under the laws of the Province of Manitoba, a limited partner of which is only liable for any of its liabilities or any of its losses to the extent of the amount that the limited partner has contributed or agreed to contribute to the capital of the limited partnership and the limited partner's pro rata share of any undistributed income. The parties hereto acknowledge that the obligations of Wuskwatim Power Limited Partnership shall not be personally binding upon, nor shall resort be had to, the property of any of the limited partners, their heirs, successors and assigns, and that resort shall only be had to the property of the Wuskwatim Power Limited Partnership or the property of its general partner. 5022649 Manitoba Ltd. is the sole general partner of the limited partnership."

Covenants of General Partner

3.03 Subject to the provisions of this **Agreement**, the **General Partner** covenants that:

(a) it will exercise the powers and discharge its duties under this **Agreement** honestly, in good faith, and in the best interests of the **Partnership**;

(b) in carrying out its obligations under this **Agreement**, it will exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances;

(c) it will maintain the confidentiality of financial and other information and data which it may obtain through or on behalf of the **Partnership**, the disclosure of which may adversely affect the interests of the **Partnership** or of a **Limited Partner**, except to the extent that disclosure is permitted as provided in this **Agreement**, is required by law, is required by virtue of the fact that **Hydro** is a Crown Corporation and must present annual financial statements for public review, or is in the best interests of the **Partnership**;

(d) it shall not carry on any operations in addition to its activities as general partner of the **Partnership** and will devote its best efforts to, and for the benefit of, the **Partnership** and will devote as much time as is necessary for the conduct and prudent management of the activities and affairs of the **Partnership**; and

(e) it will do all things and take all actions as may be necessary to ensure and protect, to the extent reasonably possible, the limited liability of the **Limited Partners**.

Conflict of Interest

3.04 Notwithstanding sections 3.03 or 3.09 or any other provision of this **Agreement**, the **Parties** acknowledge that there is an inherent conflict of interest in **Hydro** entering into the **Hydro Service Agreements** with the **Partnership**. The parties agree that the entering into of the

Hydro Service Agreements and the performance by the **General Partner** on behalf of the **Partnership** and **Hydro** of their respective obligations thereunder in accordance with their respective terms shall not constitute a breach by the **General Partner** of its obligations, fiduciary, contractual or otherwise, to the **Partnership**. It is further acknowledged and agreed that, in accordance with the provisions of the **Operations and Maintenance Agreement** and the **System Operations and Dispatch Agreement**, **Hydro**, in performing its functions under the said two agreements only, is entitled to act and may act at any time as **Hydro** in its sole discretion acting in good faith deems advisable in the best interests of the **Integrated Power System** regardless of whether a particular act, or actions, taken by **Hydro** in the best interests of the **Integrated Power System** may be detrimental to the interests of the **Partnership** or constitute a breach by **Hydro** of an agreement between it and the **Partnership**. The parties agree that neither **Hydro** nor the **General Partner** shall be liable to any **Partner** nor to the **Partnership** for any loss or damage of whatever nature the latter may incur as a consequence of the **General Partner** having entered into the **Operations and Maintenance Agreement** and the **System Operations and Dispatch Agreement** or of **Hydro**, acting in good faith, having acted in the best interests of the **Integrated Power System** as described in this section, subject to section 3.08 hereof and the review processes set out in Articles XVIII and XIX, respectively, of the **PDA**.

Other Activities of General Partner, Shareholder or Affiliates

3.05 Notwithstanding any other provision of this **Agreement**, it is expressly understood and agreed that shareholders and **Affiliates** of the **General Partner** may engage in businesses which may be similar to or competitive with those in which the **Partnership** is or might be engaged and neither the **General Partner** nor its shareholders and affiliates shall be required to offer or make available to the **Partnership** any business, other than the **Business**, or investment opportunity which its shareholders and **Affiliates** may acquire or be engaged in for their own account. The validity of a transaction, agreement or payment involving the **Partnership** and the **General Partner's** shareholders or an **Affiliate** is not affected by reason of the relationship between the **General Partner** and its shareholders or **Affiliates** nor by reason of the approval or lack thereof of the transaction, agreement or payment by the directors of the **General Partner**, all or some of whom may be involved personally or as officers or directors of, or otherwise interested in or related to, the **General Partner's** shareholders or **Affiliates**. Subject always to the receipt of such approvals as may be required under section 2.19 of the **PDA** for **Hydro** or any **Affiliate** of **Hydro** to enter into any agreements with the **Partnership** (other than the **Hydro Service Agreements**), the **General Partner** may engage or retain its shareholders or **Affiliates** on behalf of the **Partnership** to provide goods or services to the **Partnership** and may, in its discretion, engage other **Persons** interested in or companies owned by, associated with or affiliated with the **General Partner**, to render on behalf of the **General Partner**, part or all of such generalized and specialized management functions or administrative services as are reasonably required to accomplish the **Business** of the **Partnership.** This section 3.05 is not intended to detract from or limit the fiduciary obligations of the **General Partner** to the **Partnership** and shall not be deemed to do so.

Title to Partnership Assets

3.06 Title to the **Partnership Assets** shall be deemed to be owned by the **Partnership** as an entirety, and no **Partner** individually shall have any ownership interest in the assets of the **Partnership** or any portion thereof. Title to any or all of the **Partnership's** assets shall be held in the name of the **General Partner** for the benefit of the **Partnership** or in such other names as the **General Partner** may determine from time to time. The **General Partner** declares and warrants that any assets of the **Partnership** of which legal title is held in the name of the **General Partner** shall be held by the **General Partner** as agent of the **Partnership** for the use and benefit of the **Partnership** in accordance with the provisions of this **Agreement**. All of the assets of the **Partnership** shall be recorded as the property of the **Partnership** on its books and records, irrespective of the name in which legal title to such assets is held.

Expenses of the General Partner

3.07 The **Partnership** shall be directly responsible for the payment of all **Allowable Operating Expenses** and shall reimburse the **General Partner** for them, to the extent that they are not otherwise recoverable from the revenues of the **Business**, on a monthly basis, or on any other basis as the **General Partner** may determine in its sole and complete discretion, provided that the **General Partner** is not in default of its duties in connection with such expenses.

Limitation of Liability

3.08 The **General Partner** and its officers, directors, shareholders, employees, agents and **Affiliates** shall not be liable to a **Limited Partner** for any act or omission that does not constitute actual fraud, gross negligence or willful misconduct, if the **General Partner** or the **Person** acted in good faith and in a manner the **General Partner**, or the **Person**, believed to be in the interests of the **Partnership** or not opposed to the interests of the **Partnership** or pursuant to section 3.04. The **General Partner** shall indemnify the **Partnership** and the **Limited Partners** for any costs, damages, liabilities or expenses (including legal fees and expenses) suffered or incurred by the **Partnership** or the **Limited Partners** for an act or omission other than in the circumstances where the **General Partner** is excluded from liability in accordance with the immediately preceding sentence or in circumstances wherein **Hydro**, its subsidiaries and employees are either exempt from liability, or liability is limited (in which instances no more than the amounts determined through application of the sections in question shall be paid), pursuant to the provisions of sections 4(4), 13, 23(4), 24(2), 24(3) and 25(5) of the *Hydro Act,* R.S.M. 1987, c. H190 and amendments thereto (in which instances no more than the amounts determined through application of the sections in question shall be paid).

Indemnity

3.09 The **Partnership** shall indemnify the **General Partner** and its officers, directors, shareholders, employees, agents and **Affiliates** for any costs, damages, liabilities or expenses (including legal fees and expenses) suffered or incurred by them arising out of or incidental to the furtherance of the **Business**, except where the **General Partner** is not entitled to indemnity by application of section 3.08 hereof. Nothing in this provision is intended to detract from the limited liability to which the **Limited Partners** are entitled hereunder and under the **Act**.

Limited Liability of Limited Partners

3.10 Subject to the **Act** and the applicable legislation of any other jurisdiction in which the **Partnership** carries on business, and subject further to any act taken or thing done by a **Limited Partner** contrary to the provisions of this **Agreement**, the liability of each **Limited Partner** for the debts, liabilities and obligations of the **Partnership** is limited to the **Limited Partner's Capital Contribution**, plus the **Limited Partner's** *pro rata* share of any undistributed income of the **Partnership**. Where **Limited Partners** have received the return of all or part of their **Capital Contribution**, the **Limited Partners** shall be liable to the **Partnership's** creditors for any amount, not in excess of the amount returned with interest, necessary to discharge the liabilities of the **Partnership** to all creditors who extended credit or whose claims otherwise arose before the return of the **Capital Contribution.** The **General Partner** will operate the **Partnership** to ensure to the greatest extent possible the limited liability of the **Limited Partners** and will indemnify and hold harmless each **Limited Partner** (including former **Limited Partners**) for all costs, expenses, damages or liabilities suffered or incurred by the **Limited Partner** if the limited liability of that **Limited Partner** is lost, but only if that **Limited Partner's** limited liability is lost as a result of the gross negligence, wilful misconduct or fraud of the **General Partner** in performing its duties and obligations under this **Agreement**. Each **Limited Partner** (the "**Breaching Limited Partner**") will indemnify and hold harmless each of the other **Limited Partners** (including former **Limited Partners**) for all costs, expenses, damages or liabilities suffered or incurred by any such other **Limited Partner** if the limited liability of such other **Limited Partner** is lost due to an act or omission of the **Breaching Limited Partner** that constitutes a breach of this **Agreement**, gross negligence, wilful misconduct or fraud.

Power of Attorney

3.11 In consideration of the sum of $10.00, the receipt and sufficiency of which is hereby acknowledged, each **Limited Partner** hereby irrevocably and unconditionally nominates, constitutes and appoints the **General Partner** with full power of substitution, as its true and lawful attorney and agent with full power and authority in its name, place and stead and for its use and benefit to do the following, namely:

(a) make, execute, swear to, sign, acknowledge, deliver and file, including filing for recording at the appropriate public offices, as, when and where required, any and all of the following:

(i) this **Agreement** and all declarations and other instruments necessary to form, qualify or continue and keep in good standing the **Partnership** as a limited partnership under the laws of the Province of Manitoba and any other jurisdiction in which any such documents may be required or desirable;

(ii) all instruments, declarations and certificates necessary to reflect any amendment to this **Agreement** (subject to such approvals as may be required hereunder) or to the constitution of the **Partnership**; and

(iii) all conveyances, agreements and other instruments necessary or desirable to reflect the dissolution and termination of the **Partnership** and the cancellation of any certificates or declarations, subject always to the provisions of this **Agreement**, including Article 10 hereof;

(b) execute and file with any government body or instrumentality thereof of the Government of Canada or a province in Canada or any other governmental authority having jurisdiction any documents necessary to be filed in connection with the **Business**, property, assets and undertaking of the **Partnership**;

(c) execute and deliver this **Agreement** and any amendments to it approved as required under this **Agreement**;

(d) execute and deliver all such other documents or instruments on behalf of and in the name of the **Partnership** and/or the **Limited Partners** as may be deemed necessary or desirable by the **General Partner** to carry out fully the provisions of this **Agreement** and the provisions of any agreements to which it is a party;

(e) prepare, execute and file all income tax, sales tax and other tax forms, returns and elections which the **Partnership** is required to file or which are deemed desirable to be filed by the **General Partner**; and

(f) prepare and execute assignments and transfers of **Units** when necessary or desirable in accordance with the terms of this **Agreement**.

To evidence the foregoing, each **Limited Partner**, in executing a **Subscription Agreement** or in executing the form of transfer of a **Unit**, will have executed a power of attorney containing substantially the same powers set forth above. Each **Limited Partner** hereby declares that the power of attorney granted herein is irrevocable, is a power coupled with an interest, will survive the insolvency of a **Limited Partner** and will survive the assignment (to the extent of the **Limited Partner's** obligations hereunder and with respect to such actions as are necessary to effect the substitution of the assignee as a limited partner in the **Partnership**) by the **Limited Partner** of the whole or any part of the interest of the **Limited Partner** in the **Partnership** and extends to the heirs, executors, administrators, successors and assigns of the **Limited Partner** and may be exercised by the **General Partner** executing on behalf of each **Limited Partner** any instrument with a single signature as attorney and agent for all of them.

This power of attorney shall not revoke any previous general or continuing power of attorney granted by the **Limited Partner** and will not itself be revoked by any future grant of a general or continuing power of attorney by the **Limited Partner**.

This power of attorney shall not be affected by the withdrawal, resignation or deemed resignation of the **General Partner** as general partner for the **Partnership** and, upon substitution therefore of a replacement **General Partner**, may be exercised by such replacement **General Partner** as if it were an original party to this **Agreement**.

Each **Limited Partner** agrees to be bound by any representations and actions made or taken in good faith by the **General Partner** pursuant to such power of attorney in accordance with the terms hereof, and hereby waives any and all defences which may be available to contest, negate or disaffirm the action of the **General Partner** taken in good faith under such power of attorney.

Restrictions on Authority of General Partner

3.12 The **General Partner's** powers and authorities do not extend to any powers, actions or authority enumerated in Section 9.11 unless and until the requisite **Special Resolution** is passed by the applicable **Partners**. The **General Partner** will not:

(a) commingle the funds of the **Partnership** with its own funds or the funds of any of its **Affiliates** or associates or any other **Person**;

(b) dissolve the affairs of the **Partnership**, except in accordance with the provisions of Article 10;

(c) sell, exchange or otherwise dispose of all or substantially all of the assets of the **Partnership**;

(d) except in accordance with Article 4, assign, transfer or otherwise dispose of its entire interest as **General Partner** without approval of the **Limited Partners**; and

(e) enter into any agreement on behalf of the **Partnership** with **Hydro** or an **Affiliate** of Hydro that requires prior approval in accordance with section 2.19 of the **PDA** until such approval is obtained.

ARTICLE IV

WITHDRAWAL OR REMOVAL OF GENERAL PARTNER

Withdrawal of General Partner

4.01 The **General Partner** may withdraw if such withdrawal is approved by **Special Resolution** of the **Limited Partners**.

Deemed Resignation of General Partner

4.02 The **General Partner** shall be deemed to have resigned as the general partner of the **Partnership** in the event of the bankruptcy, dissolution, liquidation or winding-up of the **General Partner** (or the commencement of any act or proceeding in connection therewith which is not contested in good faith by the **General Partner**) or by the appointment by a court of competent jurisdiction of a trustee, receiver or manager of the affairs of all or substantially all of the properties of the **General Partner**. The **General Partner** shall forthwith advise the **Limited Partners** by written notice of the occurrence of any event referred to in this section 4.02. In such circumstances, the **Limited Partners** shall have the right by **Ordinary Resolution,** after consultation, to designate a successor **General Partner**.

No Removal of General Partner

4.03 The **General Partner** may not be removed by the **Partners** as the **General Partner** except by **Special Resolution**. In such circumstances, the **Limited Partners,** after consultation, shall have the right by **Ordinary Resolution** to designate a successor general partner.

Effect of Withdrawal, Deemed Resignation or Removal of General Partner

4.04 In the event of the withdrawal, deemed resignation or the removal of the **General Partner**, as provided herein, the **General Partner** shall cease to be entitled to any allocation of **Net Income** or **Net Loss** provided for herein upon the effective date of such resignation, deemed resignation or removal, but shall be entitled to its share of any allocation of **Net Income** or **Net Loss** up to such date. The withdrawing, resigning or removed **General Partner** shall be, and shall remain liable for all obligations and liabilities incurred by the **Partnership** for which the **General Partner** was liable before such withdrawal, deemed resignation or removal became effective.

Successor General Partner

4.05 A **Special Resolution** recording the withdrawal or removal of the **General Partner** may provide for the nomination and appointment of a successor **General Partner**, and the resolution in that circumstance shall become effective only on the admission of the successor **General Partner** to the **Partnership** in accordance with the provisions of this **Agreement**. Upon the occurrence of the events described in this paragraph, the successor **General Partner** shall continue the **Business** of the **Partnership** without dissolution.

On the admission of a successor **General Partner** to the **Partnership** on the resignation or removal of the **General Partner**, the resigning or retiring **General Partner** will do all things and take all steps to transfer the administration, management, control and operation of the **Business** of the **Partnership** and the books, records and accounts of the **Partnership** to the successor **General Partner** and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

On the resignation or removal of the **General Partner** and the admission of a successor **General Partner**, the resigning, or retiring, **General Partner**, at the cost of the **Partnership**, will transfer title to the **Partnership**'s property to such successor **General Partner** and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

On the resignation or removal of the **General Partner**, the **Partnership** will release and hold harmless the **General Partner** resigning or being removed from any costs, expenses, damages or liabilities suffered or incurred by the **General Partner** as a result of or arising out of events which occur in relation to the **Partnership** after such resignation or removal.

A successor **General Partner** shall not be a "non-resident" of Canada within the meaning of the ***Tax Act*** and will become a party to this **Agreement** and will agree to be bound by all of the provisions of this **Agreement** and to assume the obligations, duties and liabilities of the **General Partner** from the date the new **General Partner** becomes a party to this **Agreement**.

General Partner's Interest

4.06 The **General Partner** shall transfer all, but not less than all, of its **General Partner** interest in the **Partnership** to a successor **General Partner** appointed in accordance with the provisions of this **Agreement** or otherwise with the unanimous consent of the **Limited Partners**, provided in each case that any transferee assumes the rights and duties of the **General Partner** and agrees to be bound by the provisions of this **Agreement**.

Continuity of Partnership

4.07 In the event of the bankruptcy, insolvency, dissolution, liquidation or winding up of the **General Partner**, the **Partnership** shall not terminate but shall be continued by the then newly appointed or admitted **General Partner**.

ARTICLE V

THE UNITS

Number of Units

5.01 Subject to this **Agreement**, the **Partnership** shall be divided into **Units.** Subject to section 5.02, the Units may be sub-divided into such classes as the **General Partner** may determine are necessary or appropriate provided that the prior consent is obtained from any **Limited Partner** owning **Units** at the time of such proposed sub-division. The **Partnership** shall be authorized to issue an unlimited number of **Units**. **Units** may be issued in fractions.

Nature of Unit

5.02 Each issued and outstanding **Unit** shall be equal to each other **Unit** with respect to voting rights, the right to receive distributions from the **Partnership** and otherwise. No **Unit** shall have any preference or right in any circumstances over any other **Unit**. Each **Unit** carries the right to one vote in respect of all matters to be decided by the **Limited Partners**. Holders of fractional **Units** shall be entitled to vote as hereinafter provided. **Units** have no preference, exchange, preemptive or redemption rights. Only registered holders of **Units** will be entitled to vote or receive distributions or otherwise to exercise or enjoy the rights of **Limited Partners**.

Unit Certificates

5.03 **Unit Certificates** shall be in such form as is from time to time approved by the **General Partner** and shall be signed by the **General Partner** for and on behalf of the **Partnership**.

Unit Subscription

5.04 For each **Unit** subscribed for a **Person** shall pay to the **Partnership** the sum of $1,000 per **Unit**. The **General Partner** shall subscribe for a nominal number of **Units**, not to exceed 0.01% of the issued **Units**. Unless the Parties otherwise agree, subscriptions for **Units** shall be accepted by the **General Partner** only if they are in compliance with this **Agreement** and the **PDA**. The **General Partner** shall subscribe for, and maintain at all times while it is the general partner of the **Partnership**, such number of **Units** equal to 0.01% of the issued **Units**.

Receipt by Limited Partner

5.05 The receipt of any money, securities or other property from the **Partnership** by a **Person** in whose name any **Units** are recorded, or if such **Units** are recorded in the names of more than one **Person**, the receipt thereof by any one of such **Persons**, or by the duly authorized agent of any such **Person** in that regard, shall be a sufficient and proper discharge for that amount of money, securities and other property payable or deliverable in respect of such **Units**.

Registrar and Transfer Agent

5.06 The **General Partner**, or such other **Person** as may be appointed from time to time by the **General Partner**, shall act as **Registrar and Transfer Agent** of the **Partnership** and shall maintain such books as are necessary to record the names and addresses of the **Limited Partners**, the number of **Units** held by each **Limited Partner** and particulars of the transfer of **Units**. The **General Partner** shall cause the **Registrar and Transfer Agent** to perform all duties usually performed by a registrar and transfer agent of certificates of shares in a corporation except as the same may be modified by reason of the nature of the **Units**.

For so long as the **General Partner** shall be **Registrar and Transfer Agent**, the register of **Limited Partners** will be kept by the **General Partner** at its registered office.

Inspection of Records

5.07 The **General Partner** shall cause the **Registrar and Transfer Agent** to make the records relating to the **Limited Partners** available for inspection by any **Limited Partner**, or his agent duly authorized in writing, at the expense of such **Limited Partner**. A copy of the register of the **Limited Partners** shall be provided to any **Limited Partner** on forty-eight [48] hours notice in writing to the **Registrar and Transfer Agent**, at the expense of the **Limited Partner** requesting same.

Transfer of Units

5.08 **Partners** shall not transfer any **Units** owned by them without the unanimous consent of all **Limited Partners**, which consent can be unreasonably withheld except, no consent shall be required in the case of transfers of **Units** between **Hydro** and **Taskinigahp Power Corporation** and transfers of **Units** from the **General Partner** to a successor **General Partner** appointed in accordance with the provisions of this **Agreement,** and the refusal to consent must be reasonable in the case of transfers from **Taskinigahp Power Corporation** to another wholly owned subsidiary of **NCN** or from **Hydro** to another entity wholly owned by **Hydro**. The **General Partner** shall effect any transfer of **Units** required pursuant to the exercise of any sale or purchase right conferred upon **Hydro** or Taskinigahp Power Corporation, as the case may be, in the **Taskinigaph Power Corporation Financing Agreement**.

Restriction on Pledge of Unit(s)

5.09 Save and except for the provisions of the **NCN Financing Agreement,** the **Taskinigahp Power Corporation Financing Agreement** and the **Revenue Advances Consolidation Agreement** as described in the **PDA, Limited Partners** shall not pledge, encumber or assign their **Units** or their interests in their respective capital accounts without the unanimous consent of all **Limited Partners,** which consent can be unreasonably withheld.

Parties Not Bound To See To Trust or Equity

5.10 Except where specific provision has been made therefore in this **Agreement** or a related agreement, including such related finance agreements as may be entered into between **Hydro** and **NCN** and/or **Taskinigahp Power Corporation**, the **Registrar and Transfer Agent** may not be bound to see to the execution of any trust, express, implied or constructive, or any charge, pledge or equity to which any **Unit** or any interest therein is subject or to ascertain or inquire whether any sale or transfer of any such **Unit** or interest therein by a **Limited Partner** or his personal representative is authorized by such trust, charge, pledge or equity, or to recognize any **Person** having any interest therein except for the **Person** or **Persons** recorded as such **Limited Partner.**

Insolvency or Bankruptcy

5.11 In the event of the incapacity, death, insolvency or bankruptcy of a **Limited Partner**, the remaining **Limited Partners** shall have the right, if they so elect, to purchase the **Units** of the **Limited Partner** so incapacitated, deceased, insolvent or bankrupt for a price equal to the fair market value of such **Units** less the amount of any outstanding indebtedness in respect of such **Units** which would have to be paid to obtain the full release of any security interest in such **Units** and after making such adjustments as are reasonable on account of the limited market for the sale of the **Units** and the fact that such sale, in some circumstances, would amount only to a disposition of the minority interest in the **Partnership**, all as determined by an independent third party with expertise in the generation and sale of electricity at the time of disposition.

Lost Unit Certificates

5.12 Where a **Limited Partner** claims that the **Unit Certificate** for its **Units** has been defaced, lost, apparently destroyed or wrongly taken, the **Registrar and Transfer Agent** shall cause a new **Unit Certificate** to be issued, provided that the **Limited Partner** files with the **Registrar and Transfer Agent** a proof of loss in a form satisfactory to the **General Partner** to protect the **Registrar and Transfer Agent** and the **Partnership** from any claimants producing the lost **Unit Certificate** and provided further that the **Limited Partner** satisfies all other reasonable requirements imposed by the **Registrar and Transfer Agent**.

ARTICLE VI

CONTRIBUTIONS, ALLOCATIONS AND DISTRIBUTIONS

Capital Contribution

6.01 The capital of the **Partnership** shall be the aggregate amount of the **Capital Contributions** made by all of the **Partners** from time to time.

Separate Capital Accounts

6.02 There shall be established on the books of the **Partnership** a separate capital account for each **Partner** and each **Partner** shall be credited with the amount of its **Capital Contribution** to the **Partnership**. The capital account of each **Partner** shall be increased by the **Partner's** share of **Net Income** for each **Fiscal Year** and any additional **Capital Contributions**, and shall be decreased by distributions to the **Partner** and **Partner's** share of **Net Loss** for any **Fiscal Year**. No **Partner** shall be entitled to withdraw any part of its capital account or to receive any distribution on return of its **Capital Contribution** except as provided in this **Agreement**. The interest of a **Partner** in the **Partnership** shall not terminate by reason of a negative balance in its capital account.

Additional Capital Contributions

6.03 The **General Partner** shall be entitled to call upon the **Partners** to make additional cash contributions by way of capital investment in the **Partnership** in pro rata amounts in accordance with the number of **Units** owned by each **Partner** on the date of such call. In determining whether to make a call and the amount of the cash contribution required of the **Partners** in respect of that call the **General Partner** shall, acting honestly and in good faith, consider:

(i) the best interests of the **Partnership**;

(ii) the effect of the call and the amount of the cash contribution on each of the **Limited Partners** including the extent to which the call may dilute the interest of a **Partner**;

(iii) the current and desired **Debt Ratio** of the **Partnership**;

(iv) the amount of reserves currently being maintained by the **General Partner** for the **Partnership**, if any and the desired reserves;

(v) the cost of borrowing funds in the name of the **Partnership**; and

(vi) the amount of **Distributable Cash** of the **Partnership**, if any.

After considering the factors in clauses (i) to (vi), the **General Partner** shall decide whether to call for such additional cash contributions as the **General Partner**, acting reasonably, determines are necessary or desirable for the operation of the **Business**, including, without limiting the generality of the foregoing, cash for the costs of operating and maintaining the **Wuskwatim Project**.

If each **Partner** contributes its pro rata amount of any cash contribution demanded of it by the **General Partner** within 90 days of such demand having been received, such cash contribution will be allocated to each **Partner's** respective capital account and each **Partner** shall be issued additional **Units** in the **Partnership** in a number calculated by taking the amount contributed by such **Partner** within the 90-day period pursuant to the demand by the **General Partner** and dividing it by $1,000.00.

In the event that any **Partner** (the "**Defaulting Partner**") does not contribute the full amount demanded of it by the **General Partner** within 90 days of receiving such demand (provided that the amount demanded of such **Defaulting Partner** does not exceed an amount calculated by multiplying the aggregate amount demanded of all **Partners** by a fraction, the numerator of which is the number of **Units** owned by the **Defaulting Partner** prior to the demand, and the denominator of which is the total number of issued **Units** in the **Partnership** prior to the demand), then each of the **Partners** (including the **Defaulting Partner**) shall be issued additional **Units** in the **Partnership** in a number calculated by taking the amount contributed by such **Partner** within the 90-day period pursuant to the demand by the **General Partner** and dividing it by $1,000.00.

Hydro agrees that it shall ensure that at all times while there is one or more **Limited Partners** other than **Hydro** and the **General Partner** is a subsidiary or **Affiliate** of **Hydro**, **Hydro** shall cause the **General Partner** to make all of its **Capital Contributions** pursuant to any demand hereunder so as to maintain the **General Partner's** proportionate ownership of **Units** at a percentage not less than 0.01%.

No Interest Payable

6.04 No interest shall be payable to any **Partner** on account of its **Capital Contribution** by the **Partnership**.

Debt Ratio

6.05 Subject to section 6.03, the General Partner shall maintain the **Debt Ratio** of the **Partnership** at the percentage the **General Partner**, acting reasonably, honestly and in good faith considers advisable. The **Debt Ratio** shall be calculated to the nearest full percentage point when decisions regarding the distribution of **Distributable Cash** and regarding cash calls are to be made. The amount of the reserves as determined in accordance with section 6.06 shall not be included in calculating the **Debt Ratio**.

Reserves

6.06 The **General Partner** may cause the **Partnership** to establish reserves for capital expenditures, decommissioning costs and other legitimate business purposes and may set aside such funds for reserves as the **General Partner** shall determine to be reasonable in connection with the current operation and the future needs of the **Partnership** in order to carry on prudently the **Business**. The **General Partner** shall have the right to establish reserves as long as the **General Partner** acts reasonably and in a manner that is consistent with prudent business practices having regard to the purposes for which the reserves were established. Funds set aside as reserves shall not be considered to be a cash distribution. Reserves will be funded only out of the income or capital of the **Partnership** and not by calls for additional cash contributions. Once reserves are established, the **General Partner** need not draw on reserves prior to making calls upon **Partners** for additional cash contributions except where expenditures are required for which the reserves were established. For greater certainty, the **General Partner** shall ensure that income used to fund reserves is allocated as between the **Partners** based on their respective pro rata shares of the **Units** of the **Partnership**. The **General Partner** shall provide the **Partners** within 120 days of the end of each **Fiscal Year** with a written report on how the amount of the reserves was determined, which shall include an estimate of capital expenditures and other costs. The reasonableness of the amount of reserves being held by the **Partnership** may be reviewed in the manner set forth in Article XX of the PDA.

Determination of Net Income and Net Loss

6.07 The **Partnership** shall calculate **Net Income** and **Net Loss** according to the application of **Hydro's** accounting policies and practices, in effect from time to time, in accordance with **Generally Accepted Accounting Principles** as evidenced by an unqualified audit opinion. In the event that the application of **Hydro's** accounting policies and practices results in an inability to get an unqualified audit opinion, then the policies and practices in question will not be followed for the **Partnership.**

Allocation of Net Income and Net Loss

6.08 **Net Income** and **Net Loss** shall be allocated between the **General Partner** and the **Limited Partners** pro rata in accordance with the number of **Units** owned by each of them as of the close of business on the last day of the **Fiscal Year** as determined by the **General Partner** from time to time.

Allocation of Taxable Income and Tax Loss

6.09 In respect of each **Fiscal Year, Taxable Income, Tax Losses** and any tax credits due to the **Partnership** shall be allocated among the **Partners** in the same proportion as the allocation of **Net Income** and **Net Loss** as determined in accordance with section 6.08.

Distributions

6.10 Within 120 days of the end of each **Fiscal Year**, the **General Partner** shall provide the **Partners** with a written report showing the **General Partner's** determination of **EBITDA** and **Distributable Cash** together with its supporting calculations thereof in reasonable detail. The written report shall include disclosure of the amount of cash held by the **Partnership** and the deductions therefrom in accordance with the definition of **Distributable Cash** to arrive at the **Distributable Cash** for the relevant period. Subject to sections 6.05 and 6.06, the **General Partner** shall distribute to the **Partners** the amount of **Distributable Cash** shown on such report

within 10 business days of having provided such statement to the **Partners**. Without limiting the **General Partner's** obligation to report on, and distribute, **Distributable Cash** not less than once annually as herein contemplated, the **General Partner** may calculate the amount of and make a distribution thereof in such amounts and at such other time or times as the **General Partner** may determine from time to time, subject always to sections 6.05 and 6.06
Each **Partner** shall receive its pro rata share of distributions of **Distributable Cash** made by the **General Partner**, calculated as the amount determined by multiplying the total amount of the distribution by a fraction, in which the numerator is the number of **Units** owned by the **Partner** on the last day of the period for which such distribution is made and the denominator is the total number of **Units** owned by all **Partners** on the same date. Distributions shall not be made subject to any withholding taxes except as may be required by law.

Distributions payable pursuant to this provision will be made by electronic transfer of funds and, in the event of the failure of electronic payment methods, by cheque. Any payment by the **General Partner** to a **Partner** pursuant to this **Agreement** will be deemed to have been made upon the date of the electronic withdrawal of funds from the **General Partner's** bank account or upon the date the cheque clears the **General Partner's** bank account. Upon such payment, the **General Partner** will be discharged from all liability to the Partner in respect of such payment; provided, however, that if the electronic payment fails to deposit funds in a **Partner's** bank account or a cheque is lost or destroyed, then, upon the presentation of evidence satisfactory to the **General Partner** of such failure or loss, together with such indemnity as the **General Partner** may reasonably require, the **General Partner** will make a further electronic transfer or issue a replacement cheque to the **Partner**.

Adjustments

6.11 Any financial statements prepared and certified by the auditors of the **Partnership** as provided in this **Agreement** shall be final, binding and conclusive among the **Partners**, provided that any error or omission therein of which notice is given by any **Partner** to the **General Partner** within 180 days after the receipt of a copy thereof by such **Partner** shall be rectified and all proper adjustments made.

Return of Capital

6.12 The **Partners** shall not be entitled to a return of all or a portion of their **Capital Contributions** except as determined by the **General Partner**.

ARTICLE VII

BOOKS, RECORDS AND FINANCIAL INFORMATION

Books and Records

7.01 The **General Partner** will keep and maintain, or cause to be kept and maintained on behalf of the **Partnership** at its principal place of business, full, complete and accurate books of account and records of the business and affairs of the **Partnership** which will, without limitation, include:

(a) capital accounts for the **Partners**;

(b) **Capital Contributions** of the **Partners**;

(c) a register to record the names and addresses of the **Partners**, the number of **Units** held by each **Partner** and the particulars of registration and assignment of **Units**;

(d) a copy of this **Agreement** and any amendments to it; and

(e) a record of all payments made to Taskinigahp Trust.

Inspection by Limited Partners

7.02 Each **Limited Partner** and the duly authorized representative of each **Limited Partner** shall have the right, at any reasonable time during regular business hours and without charge, to obtain from the **General Partner**:

(a) a current list of the name and last known business or mailing address of each **Partner**;

(b) a copy of this **Agreement** and the **Declaration** and all amendments to either of them, together with executed copies of any Powers of Attorney pursuant to which this **Agreement**, and all amendments to it, have been executed;

(c) true and full information regarding the amount of cash and the description and statement of any other property and services contributed by each **Partner** and which each **Partner** has agreed to contribute in the future and the date on which each **Partner** became a **Partner**;

(d) the **Record of Limited Partners**;

(e) copies of all minutes of meetings of the **Partners** and all resolutions in writing of the **Partners** in lieu of meetings; and

(f) any other information regarding the affairs of the **Partnership** as is just and reasonable.

Financial Information

7.03 The **General Partner**, or its agent in that behalf, shall be responsible for the preparation and maintenance of internal financial records and retaining auditors with respect to the preparation of annual **Financial Statements** of the **Partnership** at the end of each **Fiscal Year**. Within five days after the receipt of audited **Financial Statements**, the **General Partner** will forward to each **Partner** appearing in the register as a **Partner** at the end of the **Fiscal Year** an annual report for the **Fiscal Year** containing:

(a) **Financial Statements** for the **Partnership** as at the end of the **Fiscal Year** with comparative **Financial Statements** as at the end of, and for the immediately preceding **Fiscal Year**;

(b) a report of the auditor on the **Financial Statements**;

(c) a report on allocations and distributions to **Partners**;

(d) the amount of reserves being maintained by the **General Partner** for the **Partnership**, and each **Partner's** allocation of such reserves;

(e) the current **Debt Ratio**; and

(f) any other information as is material to the **Business**, in the opinion of the **General Partner** (including any management letter).

The **General Partner** shall cause unaudited, monthly financial statements (also including year-to-date financial information), together with a monthly report providing month-end and year-to-date information in respect of the matters outlined in clauses (c) to (e) above) to be prepared within fifteen [15] days of the end of each month and shall forward copies of them to each **Limited Partner** appearing in the **Record of Limited Partners** as a limited partner at the end of the month to which they relate.

No later than 120 days after the end of each **Fiscal Year** of the **Partnership**, **Financial Statements** shall be prepared and certified by the auditors of the **Partnership**, for and as of the end of such **Fiscal Year**, and such **Financial Statements** shall show the assets and the liabilities of the **Partnership**, all incomes and revenues received and receivable, and all expenses, costs, and charges incurred and paid or payable by the **Partnership** in respect of such **Fiscal Year**, with the resulting **Net Income** or **Net Loss** of the **Partnership** in respect of such **Fiscal Year**, and shall also show the amounts standing to the credit of each of the **Partners** in respect of its capital account and separately in respect of the **Net Income** and **Net Loss** of the **Partnership** which has been allocated to each such **Partner** (which amount shall be set out in an account for such **Partner** called its "current account"), all in accordance with the provisions contained in this **Agreement**. The auditors of the **Partnership** shall be the auditors of **Hydro**.

The cost of preparing all such reports shall be at the **Partnership's** expense. Subject to section 7.04, each **Partner** shall be solely responsible for filing its income tax returns and reporting its share of the **Partnership's Taxable Income** or **Tax Loss**, as the case may be.

In addition to the foregoing reporting, the **General Partner** agrees to provide to each **Limited Partner** copies of the written statements provided monthly by **Hydro** to the **Partnership** in accordance with Section 5.13 of the **Project Financing Agreement**, copies of any notices and statements provided by **Hydro** to the **Partnership** pursuant to the **Project Financing Agreement,** the Access Road User Easement as described in the **PDA**, the Transmission Lease as described in the **PDA** and copies of such other business and financial information as the **General Partner** determines to be reasonable in the circumstances with the objective of keeping the **Limited Partners** informed as to matters of a material nature affecting the **Business** of the **Partnership**.

Tax Matters

7.04 The **Partnership** shall be treated as a limited partnership for federal, provincial and municipal income tax and other tax purposes. The **General Partner** shall prepare, or cause to be prepared, any federal, provincial and municipal tax or information returns required to be filed by the **Partnership** and all financial statements required by each **Partner** to enable the filing of any tax or information return which is required to be filed by such **Partner**.

ARTICLE VIII

AMENDMENTS

Amendments to be Adopted Solely by the General Partner

8.01 The **General Partner** (pursuant to the **General Partner's** Powers of Attorney from the **Limited Partners** described in section 3.07), without the consent or approval at the time of any **Limited Partner** (each **Limited Partner**, by acquiring a **Unit**, being deemed to consent to any amendment pursuant to this section 8.01), may amend any provision of this **Agreement** or the **Declaration**, and execute, swear to, acknowledge, deliver, file and record all documents required or desirable in connection with it to reflect:

(a) the omission, substitution, termination or withdrawal of any **Partner** in accordance with this **Agreement**;

(b) a change that is necessary to qualify the **Partnership** as a limited partnership or a partnership in which the **Limited Partners** have limited liability under the laws of any province or state;

(c) a change that is:

(i) of an inconsequential nature and does not adversely affect the **Limited Partners** (or any of them) in any material respect; or

(ii) required or specifically contemplated by this **Agreement** to be accomplished by the **General Partner** acting alone;

(d) a change in any provision of this **Agreement** which requires any action to be taken by or on behalf of the **General Partner** or the **Partnership** pursuant to the requirements of applicable law if the provisions of applicable law are amended, modified or revoked so that the taking of action is no longer required. The authority set forth in this paragraph shall specifically include the authority to make amendments to this **Agreement** and to the **Declaration** as the **General Partner** deems necessary or desirable in the event the **Act** is amended to eliminate or change any provision now in effect.

Notwithstanding the foregoing, the unanimous consent of all of the **Partners** shall be required for any amendments to this **Agreement** that: (i) alter the ability of the **Limited Partners** to remove the **General Partner** involuntarily; (ii) change the limited liability of any **Limited Partner**; (iii) change the right of a **Limited Partner** to vote at any meeting; (iv) change the **Partnership** from a limited partnership to a general partnership; (v) reduce the percentage of net income allocable to the **Limited Partners** to below 99.99%; (vi) adversely affect the rights and obligations of any particular **Limited Partner** without similarly affecting the rights and obligations of all other **Limited Partners** (vii) change the factors to be considered pursuant to Section 6.05 when determining whether a cash contribution is required of the **Partners** or (viii) establishes a fixed **Debt Ratio**.

The **General Partner** shall notify the **Limited Partners** of the full details of any amendment to this **Agreement** that does not require the approval of the **Limited Partners** within 10 days of the effective date of such amendment.

Amendment Procedures

8.02 Except as specifically provided in the preceding paragraph, all amendments to this **Agreement** shall be made solely in accordance with the following procedures:

(a) any amendments to this **Agreement** must be proposed by either:

(i) the **General Partner**, by submitting the text of the proposed amendment to all **Limited Partners** in writing; or

(ii) any **Limited Partner** submitting the text of the proposed amendment in writing to the **Partners**.

(b) The **General Partner** shall, within 10 days after the receipt of any proposed amendment or as soon thereafter as is reasonably practicable, submit the text of the proposed amendment to all **Limited Partners**. The **General Partner** may include in the submission its recommendation as to the proposed amendment.

(c) If any amendment is proposed pursuant to this section the **General Partner** shall seek the written consent of the **Partners** to the amendment or shall call a meeting of the **Partners** in accordance with the provisions of this **Agreement** to consider and vote on the proposed amendment. A proposed amendment shall be effective only if approved by **Special Resolution**, unless a greater or different percentage vote of the **Partners** is required by law or any other provision of this **Agreement**. The **General Partner** shall notify all **Partners** upon final adoption or rejection of any proposed amendment.

ARTICLE IX

MEETINGS

Meetings Called by General Partner

9.01 The **General Partner** may call a meeting of the **Partnership** subject to sections 9.03 and 9.04 at such time and place as it considers appropriate in its absolute discretion for the purpose of considering any matters set forth in the notice of meeting.

Meetings Called by Limited Partners

9.02 Any **Limited Partner** may give to the **General Partner** notice, accompanied by the information required to be provided under paragraph 9.04(b), signed by it requesting a meeting of the **Partnership**. The **General Partner** will, within 30 days of receipt of such notice, convene a meeting, and if it fails to do so, the **Limited Partner** requesting the meeting may convene the meeting by giving notice to the **Partners** in accordance with this **Agreement**, signed by such **Person** as the **Limited Partner** requesting the meeting specifies. Every meeting, however convened, will be conducted in accordance with this **Agreement** and the **Act**.

Place of Meeting

9.03 The annual meeting will be held on a rotational basis, unless otherwise unanimously agreed by the **Partners**, at convenient locations in northern Manitoba and southern Manitoba. Meetings can be attended by telephone conference.

Notice of Meetings

9.04 Notice of any meeting will be given to each **Partner** by prepaid ordinary mail or by personal delivery not less than fourteen [14] days (nor more than forty-five [45] days) prior to such meeting, and will state:

(a) the time, date and place of such meeting; and

(b) in general terms, the nature of the business to be transacted at the meeting in sufficient detail to enable the **Partners** to make a reasoned judgment concerning each matter to be considered at the meeting. A copy of the text of any proposed resolution shall accompany the notice of the meeting.

Corporations and Proxies

9.05 A **Partner** which is a corporation shall appoint by resolution an officer, director or other authorized person as its representative to attend, vote and act on its behalf at a meeting of **Partners**. Any **Limited Partner** entitled to vote at a meeting of **Partners** may vote by proxy if a form of proxy has been received by the **General Partner** or the chairperson of the meeting for verification prior to the time fixed by the **General Partner** preceding the meeting, or any adjournment of the meeting. A proxy purporting to be executed by or on behalf of a **Limited Partner** will be considered to be valid unless challenged at the time of or prior to its exercise. The **Person** challenging the proxy will have the burden of proving to the satisfaction of the chairperson of the meeting that the proxy is invalid and any decision of the chairperson concerning the validity of a proxy will be final. Every proxy will be substantially in the form as may be approved by the **General Partner** or as may be satisfactory to the chairperson of the meeting at which it is sought to be exercised. A vote cast in accordance with the terms of an instrument of proxy will be valid notwithstanding the previous death, incapacity, insolvency or bankruptcy of the **Limited Partner** giving the proxy or the revocation of the proxy unless written notice of that death, incapacity, insolvency, bankruptcy or revocation has been received by the chairperson of the meeting prior to the commencement of the meeting.

Attendance of Others

9.06 Any officer or director of the **General Partner** will be entitled to attend and receive notice of any meeting of **Partners**.

Chairperson

9.07 The **General Partner** may nominate an individual (including an officer, director or shareholder of the **General Partner** and who need not be a **Partner**) to be chairperson of a meeting of **Partners** and the individual nominated by the **General Partner** will be chairperson of such meeting unless the **Partners** elect a chairperson by **Ordinary Resolution**. The position of chairperson at the annual meeting of the **Partners** shall rotate annually between a nominee proposed by **Taskinigahp Power Corporation** and a nominee proposed by **Hydro**.

Quorum

9.08 The quorum for a meeting of **Partners** will consist of all **Partners** being present in person or by proxy; provided however, that if within half an hour after the time fixed for the holding of any meeting of **Partners**, all **Partners** are not present, the meeting, will be held at the same time, and, if available, the same place, not fewer than 10 days nor more than 21 days later (or if that date is not a business day, the first business day after that date), and the **Partner** which requested the meeting will give at least 7 days notice to all **Partners** of the date of the reconvening of the adjourned meeting. Such notice need not set forth the matters to be considered unless they are different from those for which the original meeting was called. At such reconvened meeting the quorum for the meeting will consist of one **Limited Partner** present in person or by proxy holding not less than 50% of the outstanding **Units**. Nothing herein shall detract from the requirement of all **Partners** being present in person or by proxy at any meeting (whether original or adjourned) at which a **Special Resolution** will be proposed for consideration and vote of the **Partners**. **Partners** can attend meetings by telephone conference.

Voting

9.09 Each question submitted to a meeting will be decided on a show of hands unless a **Partner** demands a ballot be executed by each **Partner**, in which case ballots shall be prepared and signed by each **Partner** present in person or by proxy and entitled to vote and such ballots shall be preserved. The Chairperson will be entitled to vote in respect of any **Units** pursuant to which he or she may have been appointed to vote. On any vote at a meeting of **Partners**, a declaration of the chairperson concerning the result of the vote will be conclusive absent demonstrable error.

Subject as hereinafter provided, each **Partner** present at the meeting will have one vote for each **Unit** of which it is registered as the **Unit** holder. A holder of a fractional **Unit** is entitled to one vote upon a show of hands at all meetings at which holders of that class of **Units** is entitled to vote but if a ballot is demanded, the vote of the holder of the fractional **Unit** shall only be counted as a fractional vote in the same fraction as the **Unit** held by it.

A vote requested or required concerning the election of a chairperson or an adjournment will be taken immediately on request and any other matter will be managed at the meeting or an adjournment of the meeting in such manner as the chairperson directs.

Resolutions Binding

9.10 Any resolution passed in accordance with this **Agreement** will be binding on all the **Partners** and their respective heirs, executors, administrators, successors and assigns, whether or not any such **Partner** was present in person or voted against any resolution so passed.

Powers Requiring Special Resolution

9.11 The following powers shall only be exercisable by the **General Partner** upon the Special Resolution of the **Partners**:

(a) selling, exchanging or otherwise disposing of all or substantially all of the assets of the **Partnership**;

(b) continuing the **Partnership** in the event that the **Partnership** is terminated by operation of law;

(c) changing or terminating the business of the **Partnership**;

(d) issuing to any party other than **Hydro** or **Taskinigahp Power Corporation**, or a wholly owned subsidiary of **Hydro** or **NCN**, additional **Units**;

(e) changing the auditors except in the event of a change to Manitoba **Hydro's** auditors;

(f) any amendment of this **Agreement**, except as expressly provided for herein or any amendment, alteration, modification or repeal of any **Special Resolution** previously passed by the **Partners**;

(g) dissolving or terminating the **Partnership**, other than as provided for in this **Agreement**;

(h) a merger or consolidation involving the **Partnership**;

(i) a consolidation, subdivision or reclassification of any **Units**;

(j) adding to, changing or removing any right, privilege, restriction or condition attaching to the **Units** which may reasonably be considered materially adverse to any one or more of the holders of the **Units**;

(k) any change to Article VI, provided that where **Partners** are unable to agree on a proposed change to any part of Article VI, such dispute may be referred to arbitration in accordance with the provisions of this **Agreement** and the **PDA**;

(l) requiring the **General Partner** on behalf of the **Partnership** to enforce any obligation or covenant on the part of any **Limited Partner**;

(m) consenting to any judgment in favour of **Hydro** entered in a court of competent jurisdiction against the **Partnership**; and

(n) establishing a fixed **Debt Ratio,** but for greater certainty, this Section 9.11(n) shall not be interpreted as requiring a Special Resolution before the General Partner can request the Partners to make additional cash contributions pursuant to Section 6.03.

Powers Exercisable by Ordinary Resolution

9.12 Any other matters not expressly stated in this **Agreement** (including in section 9.11) to be determined by **Special Resolution** and effected by the **General Partner** or stated in section 8.01 to be effected solely by the General Partner shall be determined by **Ordinary Resolution**.

Minutes

9.13 The **General Partner** will cause minutes to be kept of all proceedings and resolutions passed at every meeting, with copies of any resolutions of the **Partnership** to be made and entered in books to be kept for that purpose, and any minutes, if signed by the chairperson of the meeting, will be deemed to be evidence of the matters stated in them and such meeting will be deemed to have been duly convened and held and all resolutions and proceedings shown in them will be deemed to have been duly passed.

Additional Rules and Procedures

9.14 To the extent that the rules and procedures for the conduct of a meeting of the **Partners** are not prescribed in this **Agreement**, the rules and procedures will be determined by the chairperson of the meeting in accordance with *Robert's Rules of Order*.

Authorized Attendance

9.15 The **General Partner** has the right to authorize the presence of any **Person** at a meeting regardless of whether the **Person** is a **Partner**, providing that **Persons** who are not **Partners** are attending the meeting in connection with the **Business**. With the approval of the **General Partner** that **Person** is entitled to address the meeting. When requested by a **Limited Partner**, the **General Partner** shall authorize the attendance of legal counsel for the **Limited Partner** at any meeting of the **Partners**.

Consent Without Meeting

9.16 Any matter which may be addressed by the **Partners** at a meeting may be addressed by written resolution signed by all of such **Partners** in lieu of holding such meeting. In addition, any action required or permitted by this **Agreement** or any provision of law to be taken at a meeting of the **Partners**, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, shall be signed by all of the **Partners** holding all of the **Units** then issued and outstanding and entitled to vote thereon. Such consent shall have the same effect as a vote of such **Partners** and may be stated as such in any certificate or document.

ARTICLE X

DISSOLUTION AND LIQUIDATION

Events of Dissolution

10.01 The **Partnership** shall be dissolved upon the earliest to occur of any one of the following events:

(a) subject to section 4.02 of this **Agreement**, the bankruptcy, dissolution, liquidation or winding up of the **General Partner**, unless a successor **General Partner** is elected in accordance with this **Agreement** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(b) withdrawal or resignation of the **General Partner** unless a successor **General Partner** is elected in accordance with this **Agreement** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(c) the removal of the **General Partner** in accordance with section 4.03 and the failure to elect a successor **General Partner** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(d) except as otherwise provided in this **Agreement**, any other event which would cause a dissolution under the **Act**;

(e) after the passing of a resolution requiring unanimous consent in accordance with paragraph 9.11 (g);

(f) the dissolution of the **Partnership** by operation of law; and

(g) the conversion or reconstitution of the **Partnership** into another form of entity under circumstances permitted by this **Agreement**.

Appointment of Receiver

10.02 Upon the occurrence of an event described in section 10.01, the **General Partner** shall act as the Receiver (the "Receiver") of the **Partnership**. If the **General Partner** is unable or unwilling to act as the Receiver or if the event causing dissolution is set out in section 10.01(a), (b) or (c), the **Partners** shall, by **Ordinary Resolution**, appoint some other appropriate person to act as Receiver. Subject to section 10.03, the Receiver shall proceed diligently to wind up the affairs of the **Partnership** and to liquidate the **Partnership Assets** and to distribute the net proceeds from the sale of the **Partnership Assets** in the priority set out herein unless otherwise required by mandatory provisions of applicable law. During the course of such liquidation, the Receiver shall operate the **Business** and in so doing shall be vested with all the powers and authority of the **General Partner** in relation to the **Partnership** under the terms of this **Agreement**. A Receiver which is not the **General Partner** shall be paid reasonable fees and disbursements incurred in carrying out such duties.

Sale of Partnership Assets

10.03 In the event of dissolution, any sale, liquidation, distribution or other disposition of the **Partnership Assets** shall only be to **Hydro**. Not later than 120 days from a decision by the Receiver to liquidate the **Partnership Assets**, the Receiver shall sell the **Partnership Assets** to **Hydro** and **Hydro** shall purchase the **Partnership Assets** from the Receiver for an amount equal to the fair market value of such assets after making such adjustments as are reasonable on account of the limited market for the sale of the assets, all as determined by an independent third party with expertise in the generation and sale of electricity at the time of sale.

Distribution Upon Dissolution

10.04 In the event of the dissolution of the **Partnership**, the Receiver shall distribute the net proceeds from the sale of the **Partnership Assets** as follows:

(a) first, to pay the expenses of liquidation and the creditors of the **Partnership**;

(b) secondly, to provide such reserves as the Receiver considers necessary for any contingent liabilities, including the costs of foreseeable environmental requirements, of the **Partnership**;

(c) thirdly, to return the balance to the **Partners**, pro rata among them according to the capital accounts of each of them at the time.

Events Not Causing Dissolution

10.05 To the maximum extent permitted by the laws of the Province of Manitoba and notwithstanding any rule of law or equity to the contrary, the **Partnership** shall not be dissolved or terminated by admission of any new **General Partner** or **Limited Partner** or the removal, actual or deemed resignation, death, incompetence, bankruptcy, insolvency, other disability or incapacity, dissolution, liquidation, winding-up or receivership, or the admission, resignation or withdrawal of the **General Partner**, the **Limited Partners** or any **Limited Partner**, except in accordance with this **Agreement**.

Deferring Liquidation

10.06 Subject to section 10.03, upon the occurrence of an event described in section 10.01, the Receiver may defer the liquidation of the **Partnership Assets** or may distribute any of the **Partnership Assets** in kind if the **General Partner** or the Receiver determines that a sale would be impractical or would cause undue loss to the **Limited Partners**.

Reasonable Time for Winding Up

10.07 A reasonable time shall be allowed for the orderly winding up of the **Business** and affairs of the **Partnership** and the liquidation of the **Partnership Assets** pursuant to section 10.02 in order to minimize any losses otherwise attendant upon a winding up.

ARTICLE XI

MISCELLANEOUS

Notices

11.01 Any notice or other written communication which must be given or sent under this **Agreement** shall be deemed to have been validly given and received on the third business day following its sending by first class ordinary mail to the address of the **General Partner** and the **Limited Partners** as follows:

(a) in the case of the **General Partner**, at 360 Portage Avenue, Winnipeg, Manitoba R3C 0G8 (Facsimile No. 204-474-4947) or any new address as the **General Partner** may give notice of; and

(b) in the case of the **Limited Partners** to the address appearing on the register maintained by the **Registrar and Transfer Agent,** which shall include, where available, a mailing address, facsimile number and electronic mail address for each such **Limited Partner** (a **Limited Partner** may give notice to the **Registrar and Transfer Agent** of a new address for such **Limited Partner**, and the **Registrar and Transfer Agent** shall update the register accordingly).

Notices may be personally delivered or delivered by facsimile or other electronic communication and shall be deemed to be received on the day delivered or, if transmitted, as evidenced by confirmed transmission report.

Further Acts

11.02 The parties hereto agree to execute and deliver such further and other documents and perform and cause to be performed such further and other acts and things as may be necessary or desirable in order to give full effect to this **Agreement** and every part thereof.

Binding Effect

11.03 Subject to the restrictions on assignment and transfer herein contained, this **Agreement** shall inure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators and other legal representatives, successors and assigns.

Severability

11.04 Each provision of this **Agreement** is intended to be severable. If any provision hereof is illegal or invalid, such illegality or invalidity shall not affect the validity of the remainder hereof.

Counterparts

11.05 This **Agreement** may be executed in any number of counterparts (either originally or by facsimile) with the same effect as if all parties hereto had signed the same document. This **Agreement** may also be adopted in any subscription and assignment forms or similar instruments signed by a **Partner**, with the same effect as if such **Partner** had executed a counterpart of this **Agreement.** All counterparts and adopting instruments shall be construed together and shall constitute one and the same agreement.

Time

11.06 Time shall be of the essence.

Governing Law

11.07 This **Agreement** shall be governed by and construed in accordance with the laws of the Province of Manitoba and the laws of Canada applicable therein.

Dispute Resolution

11.08 The parties each agree that any disputes or claims arising out of this **Agreement** (other than a review of reserves established by the **General Partner** under section 6.06 hereof, which shall be carried out in accordance with the process set out in Article XX of the **PDA**), including, for greater certainty, any dispute about whether the General Partner has breached its fiduciary obligations to the **Partnership**, shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the **PDA** and they shall not bring any action, other than pursuant to Article XXI of the **PDA**, against any other party or against the **Limited Partnership.** The parties each agree that they shall not bring any action against any officer or director of the **General Partner**, except where such officer or director has committed fraud or has, by act or omission, done anything in respect of which such officer or director would not be entitled to indemnity from the **General Partner** under The Corporations Act (Manitoba), The Manitoba Hydro Act or such other legislation as may be applicable.

[Execution page follows]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement or caused it to be executed on their behalf by their duly authorized signing officers as of the day and year first above written.

5022649 MANITOBA LTD.

Per: ______________________________

Name: Ken R. F. Adams
Title: Chairman

TASKINIGAHP POWER CORPORATION

Per: ______________________________

Name:
Title: President

Per: ______________________________

Name:
Title: Vice-President

Per: ______________________________

Name: Shirley L. Linklater
Title: Secretary-Treasurer

THE MANITOBA HYDRO-ELECTRIC BOARD

Per: ______________________________

Name:
Title: President and Chief Executive Officer

Per: ______________________________

Name:
Title: Corporate Secretary

SCHEDULE A

WUSKWATIM POWER LIMITED PARTNERSHIP SUBSCRIPTION FORM AND POWER OF ATTORNEY

TO: WUSKWATIM POWER LIMITED PARTNERSHIP

The undersigned hereby subscribes for ____________ **Unit**(s) of Wuskwatim Power Limited Partnership (the "Limited Partnership") on the terms and as described in the Second Amended and Restated Limited Partnership Agreement, receipt of which is hereby acknowledged and tenders herewith its cheque in the amount of____________ in full payment of the aggregate subscription price for the said **Unit**(s). The undersigned agrees to be bound, as a party to and as limited partner in the **Partnership**, by the terms and conditions of the Second Amended and Restated Limited Partnership (the "**Agreement**"), as same may be amended from time to time in accordance with its terms, as if the undersigned had executed the **Agreement**.

The undersigned hereby represents, warrants and declares that:

(a) the undersigned is a "resident" of Canada within the meaning of *The Income Tax Act* (Canada);

(b) the undersigned is purchasing the **Units** as principal for its own account and not for the benefit of any other person; and

(c) this subscription agreement has been duly authorized, executed and delivered by and constitutes a legal, valid, binding and enforceable obligation of, the undersigned.

The undersigned hereby irrevocably constitutes and appoints the **General Partner** of the **Partnership**, with full power of substitution, as his or its true and lawful attorney and agent, with full power and authority in his name, place and stead to:

(a) execute, deliver, swear to and record in the appropriate public offices any and all of the following:

(i) the **Agreement**, all declarations and declarations of change required under *The Partnership Act* (Manitoba), *The Business Names Registration Act* (Manitoba) and elsewhere as may be required, and any other instruments and amendments thereto which the **General Partner** deems appropriate or necessary to form, qualify, continue and keep in good standing the **Partnership** as a limited partnership in compliance with the laws of the Province of Manitoba or elsewhere as may be required;

(ii) any instruments, certificates and any amendments thereto necessary to reflect any amendment to the Amended and Restated Limited Partnership Agreement properly approved as required pursuant to the terms of the Amended and Restated Limited Partnership Agreement; and

(iii) any conveyances, agreements and other instruments which the **General Partner** deems appropriate or necessary to reflect the dissolution and termination of the **Partnership** pursuant to the terms of the **Agreement** to be entered into on behalf of each **Partner**, including cancellation of any declarations;

(b) execute and file with any governmental body or instrumentality of the Government of Canada or of a province any documents necessary to be filed in connection with the business, property, assets and undertaking of the **Partnership**;

(c) execute and deliver such documents on behalf of and in the name of the **Partnership** and for the **Partners** as may be necessary to give effect to the purposes of the **Partnership** as described in the **Agreement**;

(d) prepare, execute and file all income tax, sales tax and other tax forms, returns and elections which the **Partnership** is required to file or which are deemed desirable to be filed by the **General Partner**; and

(e) prepare and execute assignments and transfers of **Units** when necessary or desirable in accordance with the terms of the **Agreement**.

The power of attorney granted herein is irrevocable and is a power coupled with an interest and is executed under seal and will survive the legal incapacity or mental incompetence of the undersigned and extend to the heirs, executors, administrators, successors and assigns of the undersigned. The undersigned agrees to be bound by any representation or action made or taken by the **General Partner** pursuant to this power of attorney and hereby waives any and all defences which may be available to contest, negate or disaffirm any action of the **General Partner** taken in good faith under this power of attorney.

IN WITNESS WHEREOF the undersigned has executed this subscription form and power of attorney at Winnipeg, in the Province of Manitoba, this   day of   , 20__.

______________________	______________________
Witness	Subscriber

IN WITNESS WHEREOF the Wuskwatim Power Limited Partnership has accepted this subscription form and power of attorney by its **General Partner**, 5022649 Manitoba Ltd., having caused its duly authorized proper officer to execute this subscription form and power of attorney this ____ day of   , 20___.

WUSKWATIM POWER LIMITED PARTNERSHIP
by its **General Partner**, 5022649 Manitoba Ltd.

Per: ____

AMENDED AND RESTATED POWER PURCHASE AGREEMENT

between

WUSKWATIM POWER LIMITED PARTNERSHIP

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD

DATED ~~June 28, 2006~~as of APRIL 1, 2014

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AMENDED AND RESTATED POWER PURCHASE AGREEMENT

DATED as of the ~~28th~~first day of ~~June~~April, ~~2006~~2014

B E T W E E N:

WUSKWATIM POWER LIMITED PARTNERSHIP,

(hereinafter referred to as the "Limited Partnership")

- and –

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter referred to as "Hydro")

WHEREAS pursuant to the Construction Agreement dated ~~even date herewith~~June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as project manager, Hydro either directly or indirectly through subcontractors ~~will plan, design, engineer, construct and commission~~ planned, designed, engineered, constructed and commissioned the Wuskwatim Project;

AND WHEREAS the Wuskwatim Project ~~will be~~ is being operated in conjunction with the Integrated Power System;

AND WHEREAS pursuant to the Interconnection and Operating Agreement entered into between Hydro (Transmission and Distribution Business Unit) and Hydro (Power Supply Business Unit) dated May 4, 2005 and subsequently assigned by Hydro (Power Supply Business Unit) to the Limited Partnership, the Wuskwatim Project will be interconnected to the Integrated Power System;

AND WHEREAS pursuant to the Operations and Maintenance Agreement dated ~~even date herewith~~June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as contractor, Hydro is managing and will continue to manage the operations and maintenance of the Wuskwatim Project;

AND WHEREAS pursuant to the System Operations and Dispatch Agreement dated ~~even date herewith~~June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, the Limited Partnership granted to Hydro the right and authority to control and operate the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station;

AND WHEREAS pursuant to the Power Purchase Agreement dated June 28, 2006 the Limited Partnership ~~is willing~~agreed to sell exclusively to Hydro and Hydro ~~is willing~~agreed to purchase all of the Net Actual Generation and capacity of the Wuskwatim Generating Station~~, subject to the terms and conditions and at the rates set forth in this~~;

AND WHEREAS the parties have agreed to amend and restate the Power Purchase Agreement;.

NOW THEREFORE~~ this Agreement witnesses that in consideration of the covenants and agreements herein contained~~ the Parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement and the preamble hereto, defined terms~~ used herein~~ shall have the following meanings:

"**Additional Costs**" shall have the meaning specified in Section 3.1(~~8~~h)~~.~~;

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person~~.~~;

"**Adjustments**" shall have the meaning specified in Section ~~5.1.~~2.4;

"**Agreement**" means this amended and restated Power Purchase Agreement and the schedules attached hereto and instruments in amendment or confirmation of it; "**hereof**", "**hereto**" and "**hereunder**" and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; "**Article**", "**Section**" or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement~~.~~;

~~"**Applicable Commissioning Time Period**" shall have the meaning specified in Section 2.6(1)(a).~~"**Applicable Domestic Transactions**" means those Domestic Transactions or portions thereof for energy sold during the Applicable Domestic Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice;

~~"**Applicable Long-Term Transactions**" shall have the meaning specified in Section 2.2(1)(c).~~

~~"**Applicable Long-Term Transaction Time Period**" shall have the meaning specified in Section 2.2(1)(b).~~

"**Applicable** ~~**Off-Peak Opportunity Transactions**" shall have the meaning specified in Section 2.6(1)(b).~~**Domestic Transaction Time Period**" means the twelve (12) month time period comprised of the month for which the applicable Domestic Transaction Rate is being determined plus the prior eleven (11) months;

"**Applicable Export Factor Time Period**" means the twelve (12) month time period comprised of the month for which the Export Factor is being determined plus the prior eleven (11) months plus the prior eleven (11) months;

"**Applicable Long-Term Transactions**" means the Long-Term Transactions or portion thereof for energy sold during the Applicable Long-Term Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice;

"**Applicable Long-Term Transaction Time Period**" means the twelve (12) month time period comprised of the month for which the applicable Long-Term Transaction Rate is being determined plus the prior eleven (11) months;;

"**Applicable On-Peak Opportunity Transactions**" shall have the meaning specified in Section 5.2~~(a).~~;

"**Applicable Opportunity Transaction Time Period**" ~~shall have the meaning specified in Section 2.2(3)(b).~~means the twelve (12) month time period comprised of the month for which the applicable Opportunity Transaction Rate is being determined plus the prior eleven (11);

"**Applicable Opportunity Transactions**" ~~shall have the meaning specified in Section 2.2(3)(c).~~means those Opportunity Transactions or portions thereof for energy sold during the Applicable Opportunity Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice; "**Applicable Reliability Organization**" means any reliability standards organization whose standards Hydro has contracted to adhere to or having authority in the region in which the Wuskwatim Project is located~~.~~;

"**Applicable Transaction Rate**" means the rate equal to the actual weighted average price over a twelve (12) month period, Hydro, as purchaser or as seller, is obligated to pay or is to be paid for the energy and capacity purchased or sold by Hydro;

"**Applicant**" shall have the meaning specified in Section ~~10.4.~~11.4;

"**Arbitrator**" means an arbitrator appointed in accordance with the procedures set out in Article ~~X~~XI of this Agreement~~.~~;

"**Business**" means, the business carried on by the Limited Partnership consisting of the development, ownership, operation and maintenance of the Wuskwatim Project and any activities incidental or related thereto~~.~~;

"**Business Day**" means any day on which Hydro's head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba~~.~~;

"**Canadian Dollars"** and **"$"** each mean lawful money of Canada~~.~~;

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interests in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights (other than debts securities convertible into an equity interest), warrants or options to subscribe for or acquire an equity interest in such Person~~.~~;

~~"**Commissioning Energy**" means the actual energy generated by a Generator Unit and delivered to the Point of Interconnection prior to the In Service Date for that Generator Unit.~~

"**Construction Agreement**" means the agreement dated ~~even date herewith~~June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project, and Hydro, as project manager, whereby Hydro, either directly or indirectly through subcontractors, ~~will design, engineer, construct and commission~~ designed, engineered, constructed and commissioned the Wuskwatim Project~~, as amended from time to time.~~;

~~"**Construction Start Date**" shall have the meaning ascribed thereto in the Construction Agreement.~~

"**Control**" for the purposes of this Agreement, a Person (the "**first Person**") shall be deemed to be Controlled by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

~~(i)~~ (a) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

~~(ii)~~ (b) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person, and "**Controlled**" **and** "**Controlling**" shall have the corresponding meaning~~.~~;

"**Dispute**" shall have the meaning specified in Section ~~10.4.~~11.4;

"**Dispute Notice**" shall have the meaning specified in Section ~~10.4.~~11.4;

"**Domestic Factor**" shall have the meaning specified in Section 2.11;

"**Domestic Transactions**" means all written agreements or undertakings between Hydro and a Person located in Manitoba, other than an Affiliate of Hydro for the sale of energy and capacity;

"Domestic Transaction Rate" shall have the meaning specified in Section 2.13;

"**Energy ~~Charge~~Calculation**" means the compensation determined to be payable by Hydro to the Limited Partnership for Net Actual Generation under ~~Section 2.2~~Article 2 or ~~under~~following an Energy Rate Review ~~for the Net Actual Generation received by Hydro at the Point of Interconnection.~~;

"**Energy Rate**" means the rate per MWh, Hydro will pay to the Limited Partnership in accordance with Sections ~~2.2(1)~~2.6, 2.7, 2.8 and ~~2.2(3)~~2.9 for the On-Peak Energy and the Off-Peak Energy respectively received by Hydro at the Point of Interconnection~~.~~;

"**Energy Rate Review**" means a review conducted in accordance with Article XVII of the PDA of the pricing mechanisms used under this Agreement to determine the Energy ~~Charge~~Calculations;.

"**Equivalent Canadian Dollar Amount**" means, on any day with respect to any amount of U.S. Dollars, the equivalent amount of Canadian Dollars determined by using the Bank of Canada noon spot rate quoted by the CDCFUSD index in Bloomberg to provide Canadian Dollars in exchange for U.S. Dollars at approximately 12 noon (Toronto time) on such day~~.~~;

"**Equivalent U.S. Dollar Amount**" means, on any day with respect to any amount of Canadian Dollars, the equivalent amount of U.S. Dollars determined by using the Bank of Canada noon spot rate quoted by the CDCFUSD index in Bloomberg to provide U.S. Dollars in exchange for Canadian Dollars at approximately 12 noon (Toronto time) on such day~~.~~;

"**Event of Hydro Default**" shall have the meaning specified in Section ~~9.3.~~10.3.

"**Event of Limited Partnership Default**" shall have the meaning specified in Section 9.1.

"Excess Spill Energy Review" means the review of the methodology, assumptions and pricing principles for the determination of Excess Spill Energy Revenue Adjustment pursuant to Section 9.4;

"**Expert**" means an expert appointed pursuant to the PDA to conduct an Energy Rate Review or a Transaction Rate Review~~.~~;

~~"**Final Closing Date**~~"**Export Factor**" shall have the meaning ~~ascribed thereto in the PDA.~~specified in Section 2.10;

~~"**First Operating Month**" means the month during which the first Generator Unit is In-Service.~~

"**GAAP**" means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the ~~Canadian Institution of~~ Chartered Professional Accountants of Canada, or any successor Person at such time~~.~~;

"**General Partner**" means 5022649 Manitoba Ltd. in its capacity as general partner of the Limited Partnership pursuant to the terms of the Limited Partnership Agreement~~.~~;

"**Generator Units**" means the three units, each consisting of a vertical-shaft, fixed blade propeller-type turbine and vertical umbrella-type generator ~~to be~~ installed as part of the Wuskwatim Project pursuant to the Construction Agreement and "**Generator Unit**" means any of the Generator Units~~.~~;

"**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region~~.~~;

"**Governmental Authority**" means any federal, provincial, local or other governmental, regulatory or administrative agency, court, commission, department, board or other governmental subdivision, legislature, rulemaking board, tribunal, or arbitration body having jurisdiction over either Party~~.~~;

"**GWh**" means gigawatt-hours~~.~~;

"**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the *Hydro Act*~~.~~;

"**Hydro Act**" means *The Manitoba Hydro Act*,~~ R~~C.C.S.M. ~~1987~~,, c. H190, as amended from time to time~~.~~;

"**Hydro Contractual Obligation**" means any provision of any agreement, instrument or written undertaking to which Hydro is a party or by which it or any of its Property is bound, which materially impacts on the Integrated Power System and was entered into without regard to the ownership of the Wuskwatim Project and the existence of this Agreement~~.~~;

"**Hydro Financial Year**" means, the financial year of Hydro, currently commencing on April 1 of each calendar year and ending on March 31 of the next calendar year~~.~~;

"**Hydro High Voltage Transmission System**" means that portion of the Hydro Transmission System designated by Hydro, as such, from time to time~~.~~;

"**Hydro High Voltage Transmission System Energy Losses**" shall have the meaning specified in Section ~~4.1.~~4.2;

"**Hydro Metering Equipment**" shall have the meaning specified in Section ~~4.2(1).~~4.3;

"**Hydro Transmission System**" means the transmission facilities owned and operated or operated by Hydro which are a component of the Integrated Power System~~.~~;

"**Initial Closing Date**" shall have the meaning ascribed thereto in the PDA~~.~~;

"**Initial Limited Partnership Agreement**" means the limited partnership agreement entered into between the General Partner, and Hydro in its capacity as limited partner, dated the 9th day of December, ~~2004.~~2004;

"**Initial PPA**" means the Power Purchase Agreement dated June 28, 2006 between Hydro and the Limited Partnership;

"**In-Service**" or "**In-Service Date**" means~~, in respect of~~ the date on which a particular Generator Unit~~, the date on which the particular Generator Unit is~~ was fully commissioned and

~~comes~~ came into service as evidenced by a commissioning certificate issued ~~in respect of that~~for the unit by Hydro's commissioning engineer ~~and "**In-Service**" means, in respect of a Generator Unit, when that particular Generator Unit is fully commissioned and comes into service as evidenced by a commissioning certificate issued in respect of that unit by Hydro's commissioning engineer.~~;

"**Insufficient Long-Term Transaction Year**" shall have the meaning ascribed thereto in Section ~~5.2.~~5.2;

"Insufficient Transactions" means~~, in respect of the Long Term Transaction Rate at any time,~~ for the relevant rate calculation either less than a total of 800 GWh of energy bought or sold ~~pursuant to the~~as Long-Term Transactions applicable at that time ~~and in respect of the Opportunity Transaction Rate at any time,~~ or less than a total of 1500 GWh of energy bought or sold ~~pursuant to~~as the Opportunity Transactions ~~applicable at that~~ during the time~~.~~;

"**Integrated Power System**" means the system of hydraulic and thermal electric generation and power transmission facilities owned and operated or operated by Hydro, which system is interconnected with other power utilities~~.~~;

"**Interconnection and Operating Agreement**" means the Interconnection and Operating Agreement entered into between Hydro (Transmission and Distribution Business Unit) and Hydro (Power Supply Business Unit) dated May 4, 2005, as amended or replaced from time to time and subsequently assigned by Hydro (Power Supply Business Unit) to the Limited Partnership, whereby the Wuskwatim Project will be interconnected to the Integrated Power System~~.~~;

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws~~.~~;

"**Licences**" means all authorizations, approvals, consents, registrations and certificates required by any Governmental Authority for the construction, operation or maintenance of the Wuskwatim Project~~.~~;

"**Limited Partner**" means one or both of Hydro and Taskinigahp Power Corporation as the context requires, in their capacity as limited partners of the Limited Partnership~~ and "Limited Partners" means both of Hydro and Taskinigahp Power Corporation in their capacity as limited partners of the Limited Partnership.~~ ; "**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement as amended and restated by the second and third Limited Partnership ~~Agreement~~Agreements, for the purposes of owning and directly or indirectly planning, designing, constructing, operating and maintaining the Wuskwatim Project~~.~~

"**Limited Partnership Agreement**" means the third amended and restated limited partnership agreement amending and restating the second amended and restated limited partnership agreement dated June 28, 2006 and the Initial Limited Partnership Agreement, dated ~~even date herewith~~ the same day as this Agreement between the General Partner in its capacity as General Partner and Hydro and Taskinigahp Power Corporation as limited partners~~.~~;

"**Limited Partnership Contractual Obligation**" means any provision of any agreement, instrument or undertaking to which the Limited Partnership is a party or by which it or any of its Property is bound~~.~~;

"**Long-Term Transaction Rate**" shall have the meaning specified in Section ~~2.2(1).~~2.12;

"**Long-Term Transactions**" means all written agreements or undertakings between Hydro and a Person, other than an Affiliate of Hydro, for the purchase or sale of energy ~~and~~physically crossing a Manitoba border and the cross-border capacity, which meets the following criteria:

~~(i)~~ (a) Hydro is pursuant to the written agreement or undertaking exporting or importing energy to or from electricity markets outside of Manitoba;

~~(ii)~~ (b) the written agreement or undertaking ~~is~~ was entered into on or after the Initial Closing Date;

~~(iii)~~ (c) the seller under the written agreement or undertaking has included the commitments made under the written agreement or undertaking, as a factor in the operation, planning and development of its energy system, in order to maintain sufficient resources to meet those commitments~~;~~, and either:

~~(iv)~~ (i) the time period between the date the written agreement or undertaking is entered into ~~on~~ and the date energy is first supplied pursuant to the written agreement or undertaking is at least 365 days in duration; or

~~(v)~~ (ii) if the ~~aforesaid~~ time period is less than 365 days, but the written agreement or undertaking has a component whereby energy will be supplied 365 days after the date the written agreement or undertaking is entered into, that component of the written agreement, or undertaking shall be included as part of the Long-Term Transactions~~.~~;

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in and of itself, but which cumulatively results in a material adverse effect) that precludes or materially restricts the ability of the Limited Partnership from performing any of its obligations under this Agreement~~.~~;

"**MWh**" means megawatt-hours~~.~~

"NCN Total Outstandings" means the Total Outstandings of NCN (as that term is defined in the Second NCN Financing Agreement), plus all accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility (as that term is defined in the Second NCN Financing Agreement)**;**

"**Net Actual Generation**" means the actual energy generated by the Wuskwatim Project during the applicable period less any energy generated which is used for the Wuskwatim Project's station service or auxiliaries but includes only the energy generated from each Generator Unit after its In-Service Date~~. (For greater certainty Net Actual Generation includes only On-Peak Energy and Off-Peak Energy and does not include Commissioning Energy).~~;

"**Notice**" means any written notice, citation, directive, request for information, writ, summons and statement of claim or other communication from any Person~~.~~ other than the Parties;

"**Off-Peak Energy**" means that portion of the Net Actual Generation delivered by the Wuskwatim Project to the Point of Interconnection during Off-Peak Hours~~.~~;

"**Off-Peak Energy to Date**" means the Off-Peak Energy received by Hydro during the period of time from the first day of the applicable Hydro Financial Year to the last day of the applicable month in that Hydro Financial Year for which the Off-Peak Energy Payment is to be calculated in accordance with sections 2.8 and 2.9 of this Agreement;

"**Off-Peak Hours**" means the period of time which is not included in the On-Peak Hours~~.~~;

"**Off-Peak Opportunity Transactions**" means those Opportunity Transactions where the sale or purchase of energy and capacity is in respect of energy sold or received only during ~~the~~ Off-Peak Hours~~. If~~ but if an Opportunity Transaction includes energy sold or received during Off-Peak Hours and On-Peak Hours, ~~it means~~ only those ~~provisions of that~~ Opportunity ~~Transaction that are applicable to the energy~~ Transactions sold or received ~~only~~ during ~~the~~ Off-Peak Hours~~.~~ shall be considered Off-Peak Opportunity Transactions;

~~"**Off-Peak Opportunity Transaction Rate**" shall have the meaning specified in Section 2.6(1).~~

"**On-Peak Energy**" means that portion of the Net Actual Generation delivered by the Wuskwatim Project to the Point of Interconnection during On-Peak Hours~~.~~;

"**On-Peak Energy to Date**" means the On-Peak Energy received by Hydro during the period of time from the first day of the applicable Hydro Financial Year to the last day of the applicable month in that Hydro Financial Year for which the On-Peak Energy Payment is to be calculated in accordance with section 2.6 and 2.7 of this Agreement;

"**On-Peak Hours**" means the period of time between 6:00 a.m. and 10:00 p.m. central standard time, Monday through Friday excluding holidays designated by the North American Electric Reliability Council or any successor agency~~.~~;

"**On-Peak Opportunity Transaction Rate**" shall have the meaning specified in Section ~~5.2.~~5.2;

"**On-Peak Opportunity Transactions**" means those Opportunity Transactions where the sale or purchase of energy is ~~in respect of~~ for energy sold or received only during the On-Peak Hours~~. If the~~ but if an Opportunity Transaction includes energy sold or received during ~~the~~ Off-Peak Hours and ~~the~~ On-Peak Hours, ~~it means~~ only those ~~provisions of that~~ Opportunity ~~Transaction that are applicable to the energy~~Transactions sold or received ~~only~~ during the On-Peak ~~Hours.~~ Hoursshall be considered On-Peak Transactions;

"**Operations and Maintenance Agreement**" means an agreement dated ~~even date herewith~~June 28, 2006 between the Limited Partnership, as owner of the Wuskwatim Project and Hydro, whereby Hydro will manage the operations and maintenance of the Wuskwatim Project, as amended or replaced from time to time~~.~~;

"**Opportunity Transaction Rate**" shall have the meaning specified in Section ~~2.2(3).~~2.14;

"**Opportunity Transactions**" means all agreements or undertakings between Hydro and a Person, other than an Affiliate of Hydro, for the sale or purchase of energy ~~and~~physically crossing a Manitoba border and cross-border capacity which meets the following criteria:

> ~~(i)~~ (a) the agreement or undertaking ~~is~~ was entered into on or after the Initial Closing Date;
>
> ~~(ii)~~ (b) the agreement or undertaking is not a Long-Term Transaction; and
>
> ~~(iii)~~ (c) Hydro is pursuant to the agreement or undertaking exporting or importing energy to or from electricity markets outside of Manitoba~~.~~;

"**PDA**" means ~~the~~ for purposes of this Agreement, the Wuskwatim Project Development Agreement dated June ~~26, 2006 made between Nisichawayasihk Cree Nation, Hydro, Taskinigahp Power Corporation, the General Partner and the Limited Partnership.~~28, 2006 amended by the PDA Supplement No. 1 dated March 15, 2011 and PDA Supplement No. 2 dated as of March 31, 2015;

"**Party**" means either the Limited Partnership or Hydro and "**Parties**" means both the Limited Partnership and Hydro~~.~~;

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture or other entity or Governmental Authority, and pronouns have a similarly extended meaning~~.~~;

"**Point of Interconnection**" shall mean the point on the output (high) side of the step up transformer located on the tail race deck of the Wuskwatim Generating Station at which each of the Generator Units connects to one of the three 230 kV transmission lines running from the Wuskwatim Generating Station to the switching station~~.~~;

"**Pricing Criteria**" shall have the meaning specified in Section ~~6.3.~~6.3;

"**Pricing Principle**" shall have the meaning specified in Section ~~6.2.~~6.2;

"**Property**" means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including Capital Stock in any other Person~~.~~;

"**Rate Review**" means an Energy Rate Review, an Excess Spill Energy Review or a Transaction Rate Review, as the case may be and "**Rate Reviews**" means all of them;

"**Reply**" shall have the meaning specified in Section ~~10.5.~~11.5;

"**Respondent**" shall have the meaning specified in Section ~~10.5.~~11.5;

"**Second NCN Financing Agreement**" means the amended and restated NCN Financing Agreement dated April 16, 2015;

"Second TPC Financing Agreement" means the amended and restated TPC Financing Agreement dated April 16, 2015;

"**System Operations and Dispatch Agreement**" means an agreement dated even date herewith, between the Limited Partnership and Hydro whereby Hydro will control and operate the Wuskwatim Project on behalf of the Limited Partnership, including matters related to the dispatch of the Wuskwatim Generating Station as amended or replaced from time to time~~.~~;

"TPC Total Outstandings" means the Total Outstandings of TPC (as that term is defined in the Second TPC Financing Agreement), plus all accrued and unpaid interest and all other amounts owing by NCN under the Equity Credit Facility (as that term is defined in the Second TPC Financing Agreement);

"**Term**" means the initial ~~Term~~and subsequent term of this Agreement as specified in Section ~~2.7(1) plus any extension of the Term pursuant to Section 2.7(2).~~2.19;

"**Transaction Rate Review**" means a review conducted in accordance with Article XVII of the PDA of the determination, allocation and ~~adjustments~~Adjustments made by Hydro pursuant to ~~Sections 2.2(1)(c), (d) and (e) and 2.2(3)(c), (d) and (e)~~Article 2 of this Agreement in the calculation~~, from time to time,~~ of the Long~~-~~ Term Transaction Rate, the Domestic Transaction Rate and the Opportunity Transaction Rate~~.~~;

"**Transmission Owner Interconnection Facilities**" shall have the meaning ascribed thereto in the Interconnection and Operating Agreement~~.~~;

"**U.S. Dollars** means lawful money of the United States of America~~.~~;

"**Wuskwatim Generating Station**" shall have the meaning ascribed thereto in the PDA~~.~~; and

"**Wuskwatim Project**" shall have the meaning ascribed thereto in the PDA.

1.2 Interpretation.

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, or any provisions hereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(e) the expressions "the aggregate", "the total", "the sum" and expressions of similar meaning shall mean "the aggregate (or total or sum) without duplication";

(f) in the computation of periods of time, unless otherwise expressly provided, the word "from" means "from and including" and the words "to" and "until" mean "to but excluding"; and

(g) accounting terms not specifically defined shall be construed in accordance with GAAP.

1.3 Severability.

If any provision of this Agreement is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions ~~hereof shall be unaffected by such provision and~~ of this Agreement shall continue to be valid and enforceable.

1.4 Entire Agreement.

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, of the Parties, whether oral or written, ~~of the parties relating to the subject matter hereof and entered into~~ prior to the date of this Agreement.

1.5 Waiver.

No failure on the part of a Party to exercise, and no delay in exercising, any right under this Agreement shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement preclude any other or further exercise thereof or the exercise of any other right; nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No Notice to or demand on the Limited Partnership in any case shall entitle it to any Notice or demand in similar or other circumstances. No waiver of any of the provisions of this Agreement shall be effective unless it is in writing duly executed by the waiving Party.

1.6 No Presumption.

The Parties have endeavoured to ensure that the terms of this Agreement are as clear~~ as possible and in interpreting this Agreement and except where~~ and unambiguous so unless expressly provided there shall be no presumption in favour of or against any Party.

1.7 Governing Law.

This Agreement shall be governed by, and interpreted in accordance with, the applicable Laws of Manitoba and ~~the Laws of~~ Canada~~ applicable therein~~.

1.8 Incorporation of Schedules.

The following schedules ~~attached~~ shall~~, for all purposes hereof,~~ be incorporated ~~in~~into and form an integral part of this Agreement:

Schedule A	-	Arbitrator's Undertaking
Schedule B	-	Notices

1.9 Acknowledgement.

The Parties acknowledge that :

(a) the Limited Partnership is a limited partnership formed under the Laws of Manitoba, ~~a~~and each limited partner ~~of which~~ is only liable for ~~any of~~ its respective liabilities or ~~any of its~~ losses to the extent of the amount that the limited partner has contributed or agreed to contribute to the capital of the limited partnership and the limited partner's pro rata share of any undistributed income~~. The Parties acknowledge that~~;

(b) the obligations of the Limited Partnership shall not be personally binding upon, nor shall resort be had to, the property of any of the limited partners, their successors and assigns, and that resort shall only be had to the property of the Limited Partnership or the property of its ~~general partner. The~~General Partner;

(c) the General Partner is the sole general partner of the Limited Partnership~~. Nothing~~; and

(d) nothing in this Agreement shall be deemed to detract from or limit or restrict in any way the limited liability of any ~~limited partner of the~~ Limited ~~Partnership~~Partner.

ARTICLE II

SALE AND PURCHASE OF ENERGY

2.1 Net Actual Generation and Charge.

~~(1)~~ Subject to the terms and conditions of this Agreement, the Limited Partnership agrees to sell and Hydro agrees to purchase the Net Actual Generation and capacity of the Wuskwatim Project~~.~~ and the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection determined in accordance with Sections 2.2 and 2.3 and capacity in accordance with Section 2.4.

~~(2) The Limited Partnership agrees that it shall not enter into any agreement or instrument or undertake to sell and it shall not sell any energy or capacity from the Wuskwatim Project to any Person other than Hydro.~~

~~**2.2 Energy Charge.**~~

2.2 Energy Calculations – Financial Years 2014/15 to 2023/24.

Subject to the terms and conditions of this Agreement including ~~adjustments, if any, provided for in Articles V and VI, the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection, on a Canadian Dollar per MWh basis, determined in the following manner:~~

~~On-Peak Energy~~

~~(1) Hydro shall pay to the Limited Partnership each month in the manner hereinafter set forth, subject to the adjustments provided for in this Agreement and the set-off of all amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), for the On-Peak Energy received by Hydro at the Point of Interconnection, during any particular Hydro Financial Year, based on a rate that is equal to the actual weighted average price over a twelve (12) month period, that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, for the energy and capacity, purchased or sold by Hydro, pursuant to all applicable Long-Term Transactions during that twelve (12) month period (the "**Long-Term Transaction Rate**") determined in the following manner:~~

~~(a) the Long-Term Transaction Rate will be determined for each month during the Hydro Financial Year;~~

~~(b) the twelve (12) month time period shall be comprised of the month for which the rate is being determined plus the prior eleven (11) months (the "**Applicable Long-Term Transaction Time Period**");~~

~~(c) only those Long-Term Transactions or portions thereof applicable to the time period where the energy sold or purchased physically crossed the Manitoba border and were delivered during the Applicable Long-Term Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice, (the "**Applicable Long-Term Transactions**") shall be included in determining the actual weighted average price over the Applicable Long-Term Transaction Time Period;~~

~~(d) Hydro, acting reasonably, in addition to all other allocations or adjustments that may be required, shall include the portion of the price, if any, that is payable for capacity, which is attributable to that portion of the energy that physically crossed the Manitoba border and was delivered during the Applicable Long-Term Transaction Time Period for each of the Applicable Long-Term Transactions in determining the actual average weighted price over the Applicable Long-Term Transaction Time Period;~~

~~(e) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Long-Term Transactions shall be adjusted by Hydro, acting reasonably to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Long-Term Transactions. The charges or credits will include actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement;~~

~~(f) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Long-Term Transactions shall be determined in Canadian Dollars per MWh and if Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid in U.S. Dollars pursuant to any of the Applicable Long-Term Transactions, the amounts shall be converted to Canadian Dollars (after the adjustments referred to in this Section 2.2(1)) by reference to the Equivalent Canadian Dollar Amount on the last Business Day of the month, during which the said obligation to pay, or the entitlement to be paid the said amount arises; and~~

~~(g) the Long-Term Transaction Rate shall be expressed in Canadian Dollars per MWh and shall be calculated by dividing (i) the total net amount that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, pursuant to the Applicable Long-Term Transactions, determined in accordance with this Section 2.2(1); by (ii) the total energy that was imported or exported by Hydro pursuant to the Applicable Long-Term Transactions, determined in accordance with this Section 2.2(1).~~

~~(2) The monthly amount to be paid to the Limited Partnership for the On-Peak Energy shall be calculated as follows:~~

~~First Operating Month~~

~~(a) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of the First Operating Month with the Long-Term Transaction Rate determined for that month. The amount to be paid for the On-Peak Energy received by Hydro from the Final Closing Date to the last day of the First Operating Month, subject to subsequent adjustment, if any, pursuant to Article V, and the set-off of all amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Long-Term Transaction Rate, determined for the First Operating Month; multiplied by~~

~~(ii) the On-Peak Energy received by Hydro during that period, as determined pursuant to Section 4.1.~~

~~First Operating Year~~

~~(b) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of each subsequent month during the Hydro Financial Year in which the First Operating Month occurs (except where that month is the last month of the Hydro Financial Year in which case the period of time shall be extended to fifteen (15) Business Days) with the Long-Term Transaction Rate determined for each month. The amount to be paid for the On-Peak Energy received by Hydro during those months, subject to subsequent adjustment, if any, pursuant to Article V, and the set-off of all unpaid amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Long-Term Transaction Rate determined for the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(b); multiplied by~~

~~(ii) the On-Peak Energy received by Hydro during that period of time from the Final Closing Date to the last day of the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(b), as determined in accordance with the provisions of Section 4.1; less~~

~~(iii) all amounts Hydro has paid or is obligated to pay pursuant to Sections 2.2(2)(a) and 2.2(2)(b) for the On-Peak Energy received by Hydro during the period of time, from the Final Closing Date to the last day of the month, in that Hydro Financial Year immediately prior to the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(b).~~

~~Subsequent Operating Years~~

~~(c) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of each month during each subsequent Hydro Financial Year (except where that month is the last month of a Hydro Financial Year in which case the period of time shall be extended to fifteen (15) Business Days) with the Long-Term Transaction Rate determined for each month. The amount to be paid for the On-Peak Energy received by Hydro during each month within a Hydro Financial Year, subject to subsequent adjustment, if any, pursuant to Article V and the set-off of all unpaid amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Long-Term Transaction Rate determined for the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(c); multiplied by~~

~~(ii) the On-Peak Energy received by Hydro during that period of time from the first day of the applicable Hydro Financial Year to the last day of the particular month in that Hydro Financial Year in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(c), as determined in accordance with the provisions of Section 4.1; less~~

~~(iii) all amounts Hydro has paid or is obligated to pay pursuant to this Section 2.2(2)(c) for the On-Peak Energy received by Hydro during the period of time, from the first day of the applicable Hydro Financial Year to the last day of the month in that Hydro Financial Year, immediately prior to the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(2)(c).~~

~~Off Peak Energy~~

~~(3) Hydro shall pay to the Limited Partnership in the manner hereinafter set forth, subject to the adjustments provided for in this Agreement and the set off of all amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), for the Off-Peak Energy received by Hydro at the Point of Interconnection, during any particular Hydro Financial Year, based on a rate that is equal to the actual weighted average price over a twelve (12) month period that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, for the energy and capacity purchased or sold by Hydro pursuant to all applicable Opportunity Transactions during that twelve (12) month period (the "**Opportunity Transaction Rate**") determined in the following manner:~~

~~(a) the Opportunity Transaction Rate will be determined for each month during the Hydro Financial Year;~~

~~(b) the twelve (12) month time period shall be comprised of the month for which the rate is being determined plus the prior eleven (11) months (the "**Applicable Opportunity Transaction Time Period**");~~

~~(c) only those Opportunity Transactions or portions thereof applicable to the time period where the energy sold or purchased physically crossed the Manitoba border and were delivered during the Applicable Opportunity Transaction Time Period, as determined by Hydro in accordance with Good Utility Practice, (the "**Applicable Opportunity Transactions**") shall be included in determining the actual weighted average price over the Applicable Opportunity Transaction Time Period;~~

~~(d) Hydro, acting reasonably, in addition to all other allocations or adjustments that may be required, shall include the portion of the price, if any, that is payable for capacity, which is attributable to that portion of the energy that physically crossed the Manitoba border and was delivered during the Applicable Opportunity Transaction Time Period for each of the Applicable Opportunity Transactions in~~

~~determining the actual average weighted price over the Applicable Opportunity Transaction Time Period;~~

~~(e) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Opportunity Transactions shall be adjusted by Hydro, acting reasonably to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Opportunity Transactions. The charges or credits will include actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement;~~

~~(f) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Opportunity Transactions shall be determined in Canadian Dollars per MWh and if Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid in U.S. Dollars pursuant to any of the Applicable Opportunity Transactions, the amounts shall be converted to Canadian Dollars (after the adjustments referred to in this Section 2.2(3)) by reference to the Equivalent Canadian Dollar Amount on the last Business Day of the month, during which the said obligation to pay, or the entitlement to be paid the said amount arises; and~~

~~(g) the Opportunity Transaction Rate shall be expressed in Canadian Dollars per MWh and shall be calculated by dividing (i) the total net amount that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, pursuant to the Applicable Opportunity Transactions, determined in accordance with this Section 2.2(3); by (ii) the total energy that was imported or exported by Hydro pursuant to the Applicable Opportunity Transactions, determined in accordance with this Section 2.2(3).~~

~~(4) The monthly amount to be paid to the Limited Partnership for the Off-Peak Energy shall be calculated as follows:~~

~~First Operating Month~~

~~(a) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of the First Operating Month with the Opportunity Transaction Rate determined for that month. The amount to be paid for the Off-Peak Energy received by Hydro from the Final Closing Date to the last day of the First Operating Month, subject to subsequent adjustment, if any, pursuant to Article V, and the set-off of all unpaid amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Opportunity Transaction Rate, determined for the First Operating Month; multiplied by~~

~~(ii) the Off-Peak Energy received by Hydro during that period, as determined pursuant to Section 4.1.~~

~~First Operating Year~~

~~(b) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of each subsequent month during the Hydro Financial Year in which the First Operating Month occurs (except where that month is the last month of the Hydro Financial Year in which case the period of time shall be extended to fifteen (15) Business days) with the Opportunity Transaction Rate determined for each month. The amount to be paid for the Off-Peak Energy received by Hydro during those months, subject to subsequent adjustment, if any, pursuant to Article V and the set-off of all unpaid amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Opportunity Transaction Rate determined for the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(4)(b); multiplied by~~

~~(ii) the Off Peak Energy received by Hydro during that period of time from the Final Closing Date to the last day of the particular month in respect of which the payment amount is to be calculated pursuant to this Section~~

~~2.2(4)(b), as determined in accordance with the provisions of Section 4.1; less~~

~~(iii) all amounts Hydro has paid or is obligated to pay pursuant to Sections 2.2(4)(a) and 2.2(4)(b) for the Off-Peak Energy received by Hydro during the period of time, from the Final Closing Date to the last day of the month in that Hydro Financial Year immediately prior to the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(4)(b).~~

~~Subsequent Operating Years~~

~~(c) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of each month during each subsequent Hydro Financial Year (except where that month is the last month of a Hydro Financial Year in which case the period of time shall be extended to fifteen (15) Business Days) with the Opportunity Transaction Rate determined for each month. The amount to be paid for the Off-Peak Energy received by Hydro during each month within a Hydro Financial Year, subject to subsequent adjustment, if any, pursuant to Article V, and the set-off of all unpaid amounts the Limited Partnership is obligated to pay to Hydro pursuant to the provisions of Section 3.1(11), shall be equal to:~~

~~(i) the Opportunity Transaction Rate determined for the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(4)(c); multiplied by~~

~~(ii) the Off-Peak Energy received by Hydro during that period of time from the first day of the applicable Hydro Financial Year to the last day of the particular month in that Hydro Financial Year in respect of which the payment amount is to be calculated pursuant to this Section 2.2(4)(c), as determined in accordance with the provisions of Section 4.1; less~~

~~(iii) all amounts Hydro has paid or is obligated to pay pursuant to Section 2.2(4)(c) for the Off-Peak Energy received by Hydro during the period of time, from the first day of the applicable Hydro Financial Year to the last~~

~~day of the month in that Hydro Financial Year, immediately prior to the particular month in respect of which the payment amount is to be calculated pursuant to this Section 2.2(4)(c)~~any Adjustments, Rate Reviews and the set-off of any amounts the Limited Partnership is obligated to pay Hydro pursuant to the provisions of Section 3.1(j), for the Hydro Financial Years 2014/15 to 2023/24 the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection, on a Canadian Dollar per MWh basis, determined by calculating the On-Peak Energy in accordance with Section 2.6, the Off-Peak Energy in accordance with Section 2.8, the On-Peak Energy to Date, the Off-Peak Energy to Date, the Export Factor in accordance with Section 2.10, the Domestic Factor in accordance with Section 2.11, the Long Term Transaction Rate in accordance with Section 2.12, the Domestic Transaction Rate in accordance with Section 2.13, the Opportunity Transaction Rate in accordance with Section 2.14 and the Spill Energy Revenue Adjustment in accordance with Article IX.

2.3 Energy Calculations – Financial Years 2024/25 and Onward.

Subject to the terms and conditions of this Agreement including any Adjustments, Rate Reviews and the set-off of all amounts the Limited Partnership is obligated to pay Hydro pursuant to the provisions of Section 3.1(j), for the Hydro Financial Years commencing April 1, 2024 and each Hydro Financial Year thereafter the Limited Partnership shall be compensated by Hydro for the Net Actual Generation received by Hydro at the Point of Interconnection, on a Canadian Dollar per MWh basis, determined by calculating the On-Peak Energy in accordance with Section 2.7, the Off-Peak Energy in accordance with Section 2.9, the On-Peak Energy to Date, the Off-Peak Energy to Date, the Export Factor in accordance with Section 2.10, the Long Term Transaction Rate in accordance with Section 2.12, the Opportunity Transaction Rate in accordance with Section 2.14, and the Spill Energy Revenue Adjustment in accordance with Article IX.

2.4 Allocations and Adjustments.

When making the Energy Calculations in Sections 2.2 and 2.3 Hydro, acting reasonably shall make the allocations and adjustments permitted by this Agreement, including in the case of energy exported and sold across Manitoba borders, (i) the portion of the price, if any, payable for capacity attributable to the portion of the energy that physically crossed a Manitoba border; and (ii) the actual costs or expenses incurred which were reasonably necessary to provide access to export markets or facilitate Hydro entering into export markets, but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses for which Hydro has been reimbursed pursuant to other provisions of this Agreement ("the **Adjustments**");

2.5 Hydro to Provide Monthly Information to the Limited Partnership.

Hydro shall, within ten (10) Business Days of the last day of each month during each Hydro Financial Year except in the last month, in which case, within fifteen (15) Business Days, provide the Limited Partnership with written notice of:

(a) the Domestic Transaction Rate;

(b) the Long Term Transaction Rate;

(c)the Opportunity Transaction Rate; and

(d) the amounts paid for On-Peak Energy and Off-Peak Energy for the month less any Adjustments or set-off pursuant to Section 3.1(j);

2.6 On-Peak Energy Payment - Financial Years 2014/15 to 2023/24.

For each month in a Hydro Financial Year from April 1, 2014 to March 31, 2024, Hydro shall pay to the Limited Partnership for On-Peak Energy an amount equal to the product of the monthly Long Term Transaction Rate, the On Peak Energy to Date, and the Export Factor plus the product of the Domestic Transaction Rate, the On-Peak Energy to Date and the Domestic Factor, minus the sum of the amounts paid or payable by Hydro for On-Peak Energy to the end of the prior month ("**On-Peak Energy Payments to Date**"). The calculation of the amount payable for On-Peak Energy under this Section 2.6 may be expressed by the following formula:

(A x B x C) + (D x B x E) – On-Peak Energy Payments to Date

Where:

A = Long Term Transaction Rate

B = On Peak Energy to Date

C = Export Factor

D = Domestic Transaction Rate

E = Domestic Factor

2.7 On- Peak Energy Payments - Financial Years 2024/25 and Onward.

For each month in the Hydro Financial Year commencing April 1, 2024 and thereafter Hydro shall pay to the Limited Partnership for On-Peak Energy an amount equal to the product of the monthly Long Term Transaction Rate, the On Peak Energy to Date, and the Export Factor minus the On-Peak Energy Payments to Date. The calculation of the amount payable for On-Peak Energy under this Section 2.7 may be expressed by the following formula:

(A x B x C) – On-Peak Energy Payments to Date

Where:

A = Long Term Transaction Rate

B = On Peak Energy to Date

C = Export Factor

2.8 Off-Peak Energy Payments - Financial Years 2014/15 to 2023/24.

For each month in a Hydro Financial Year from April 1, 2014 to March 31, 2014, Hydro shall pay to the Limited Partnership for Off-Peak Energy an amount equal to the product of the Opportunity Transaction Rate, the Export Factor and the Off Peak Energy To Date, plus the product of the Domestic Transaction Rate, the Off-Peak Energy to Date and the Domestic Factor, minus the sum of the amounts paid or payable by Hydro for Off-Peak Energy to the end of the prior month ("**Off-Peak Energy Payments to Date**"). The calculation of the amount payable for Off-Peak Energy under this Section 2.8 may be expressed by the following formula:

(F x G x C) + (D x G x E) – Off-Peak Energy Payments to Date

Where:

C = Export Factor

D = Domestic Transaction Rate

E = Domestic Factor

F = Opportunity Transaction Rate

G = Off-Peak Energy to Date

2.9 Off-Peak Energy Payment Financial Years 2024/25 and Onward.

For each month in the Hydro Financial Years commencing April 1, 2024 and thereafter, Hydro shall pay to the Limited Partnership for Off-Peak Energy an amount equal to the product of the Opportunity Transaction Rate, the Export Factor and the Off-Peak Energy To Date minus the Off-Peak Energy Payments to Date. The calculation of the amount payable for Off-Peak Energy under this Section 2.9 may be expressed by the following formula:

(F x G x C) – Off-Peak Energy Payments to Date

Where:

C = Export Factor

F = Opportunity Transaction Rate

G = Off-Peak Energy to Date

2.10 Export Factor.

The "**Export Factor**" means a factor that is equal to the weighted average proportion of Net Energy Delivered by the Integrated Power System over a twelve (12) month period that is exported by Hydro, during that twelve (12) month period. The monthly Export Factor shall be calculated for each month during the Hydro Financial Year using the following formula:

A / (A + B) where,

A is equal to the total energy generated by Hydro related to the export sales that physically crossed a Manitoba border; and

B is equal to the total energy generated by Hydro delivered in Manitoba

For any period from and after April 1, 2024 the monthly Export Factor shall be one (1.00).

2.11 Domestic Factor.

The Domestic Factor means a factor equal to one (1.00) minus the monthly Export Factor for each month during the Hydro Financial Year.

2.12 Long-Term Transaction Rate.

The "**Long-Term Transaction Rate**" means the Applicable Transaction Rate for Long-Term Transactions determined for each month during a Hydro Financial Year for the applicable Long Term Transaction Time Period determined in the following manner:

(a) adjustments to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Long-Term Transactions;

(b) the price paid or payable for Applicable Long-Term Transactions determined in Canadian Dollars per MWh, and if the payments are in U.S. Dollars for any of the Applicable Long Term Transactions the amounts shall be converted to Canadian Dollars pursuant to Section 2.15 after the adjustments referred to in Section 2.12 (b) using the average Equivalent Canadian Dollar Amount for the month during which the entitlement to be paid arises; and

(c) the Long-Term Transaction Rate expressed in Canadian Dollars per MWh calculated by dividing the total net amount that Hydro is entitled to be paid or is obligated to pay for the Applicable Long-Term Transactions by the total energy imported or exported as Applicable Long-Term Transactions.

2.13 Domestic Transaction Rate.

The "**Domestic Transaction Rate**" means the Applicable Transaction Rate for Domestic Transactions determined for each month during a Hydro Financial Year for the Applicable Domestic Transactions expressed in Canadian Dollars per MWh and calculated by dividing the total net amount Hydro is entitled to be paid or is obligated to pay for the Applicable Domestic Transactions by the total energy delivered as Applicable Domestic Transactions.

2.14 Opportunity Transaction Rate.

The "**Opportunity Transaction Rate**" means the Applicable Transaction Rate for Opportunity Transactions determined for each month during a Hydro Financial Year for the applicable Opportunity Transaction Time Period determined in the following manner:

(a) adjustments to reflect the price at a Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Opportunity Transactions;

(b) the price paid or payable for Applicable Opportunity Transactions determined in Canadian Dollars per MWh, and if the payments are in U.S. Dollars for any of the Applicable Opportunity Transactions the amounts shall be converted to Canadian Dollars in accordance with Section 2.15 after the adjustments referred to in Section 2.16 (b) using the average Equivalent Canadian Dollar Amount for the month during which the entitlement to payment arises; and

(c) the Opportunity Transaction Rate expressed in Canadian Dollars per MWh and calculated by dividing the total net amount Hydro is entitled to be paid or obligated to pay for the Applicable Opportunity Transactions by the total energy delivered as Applicable Opportunity Transactions.

~~2.3~~ 2.15 U.S. Dollar Conversion Option.

The Limited Partnership can if it has provided written notice to Hydro on or before the last Business Day of any particular month require that a percentage not exceeding fifty percent (50%) of the amount that would otherwise be billed to Hydro in Canadian Dollars ~~in accordance with Sections 2.2 and 8.1(2)~~, for the Net Actual Generation received by Hydro during that month, be converted to U.S. Dollars, by reference to the Equivalent U.S. Dollar Amount as of the last Business Day of that month and that amount shall be paid to the Limited Partnership, in U.S. Dollars, by the dates specified in accordance with Section 8.1(3).

~~2.4~~ 2.16 Acknowledgement of Limited Partnership.

The Limited Partnership expressly acknowledges and agrees that:

(a) the compensation to be paid under this Agreement entitles Hydro to receive all the capacity and the energy from the Wuskwatim Project;

(b) the rates and compensation to be paid in this Agreement, subject to Section ~~2.5,~~2.20 is based on the Net Actual Generation actually received by Hydro at the Point of Interconnection; and

(c) the Limited Partnership is not entitled to an additional payment or separate rate for the capacity of the Wuskwatim Project which Hydro is entitled to receive pursuant to this Agreement.

~~2.5~~ 2.18 Insufficiency of Capacity ~~or~~, Disruption or Failure of the Hydro Transmission System.

Notwithstanding any other provision of this Agreement, if the Net Actual Generation cannot be generated and delivered to the Point of Interconnection primarily due to insufficient capacity of the Hydro Transmission System or the disruption to or failure of the Hydro Transmission System and as a direct consequence thereof, water is spilled at the Wuskwatim Project spillway, Hydro shall be deemed for the purposes of this Agreement to have received the energy that could have been generated from the water that was spilled at the Wuskwatim Project spillway during that time period less the applicable Hydro High Voltage Transmission System Energy Losses. This Section ~~2.5~~2.18 shall not apply and Hydro shall not be deemed for the purposes of this Agreement or otherwise to have received energy that was not generated and delivered to the Point of Interconnection if the insufficient capacity of the Hydro Transmission System, disruption to or failure of the Hydro Transmission System occurred as a result of or was primarily due to: (i) a breach by the Limited Partnership of any provision of the Limited Partnership's Contractual Obligation; or (ii) any act or omission reasonably associated with the provisions of the Construction Agreement, the System Operations and Dispatch Agreement or the Operations and Maintenance Agreement, including without limiting the generality of the foregoing in respect of services or work performed or to be performed by Hydro under the provisions of those Agreements or the breach by Hydro of any provision of those Agreements. If this Section ~~2.5~~ 2.18 is applicable, Hydro shall provide to the Limited Partnership a calculation of the amount of energy that could have been generated and delivered during the applicable time period from the water that was spilled using the best information and data available and Hydro shall be required to pay to the Limited Partnership the amount that would otherwise be determined to be owing pursuant to the provisions of this Agreement (after all set-offs, deductions and adjustments provided for in this Agreement including adjustment for the Hydro High Voltage Transmission System Energy Losses applicable for the period of time during which water was spilled) if that amount of energy had been generated and delivered to the Hydro Transmission System during that period of time from the water that was spilled. The Limited Partnership expressly acknowledges that the risk of the Limited Partnership not being able to generate and deliver energy to the Point of Interconnection from all other matters or circumstances is borne solely by the Limited Partnership.

~~**2.6 Commissioning Energy.**~~

~~(1) Subject to the terms and conditions of this Agreement the Limited Partnership shall be compensated by Hydro for the Commissioning Energy received by Hydro at the Point of Interconnection on a Canadian Dollar per MWh basis during any particular month, based on a rate that is equal to the actual weighted average price for that month that Hydro, as purchaser is obligated to pay or Hydro, as seller, is entitled to be paid, for the energy and capacity, purchased or sold by Hydro pursuant to all applicable Off-Peak Opportunity Transactions during that month (the "**Off-Peak Opportunity Transaction Rate**") determined in the following manner:~~

~~(a) the Off-Peak Opportunity Rate will be determined for each month during the Hydro Financial Year that Commissioning Energy (the "**Applicable Commissioning Time Period**") is received by Hydro;~~

~~(b) only those Off-Peak Opportunity Transactions or portions thereof applicable to the time period where the energy sold or purchased physically crossed the~~

~~Manitoba border and were delivered during the Applicable Commissioning Time Period, as determined by Hydro in accordance with Good Utility Practice, (the "**Applicable Off-Peak Opportunity Transactions**") shall be included in determining the actual weighted average price for the Applicable Commissioning Time Period;~~

~~(c) Hydro, acting reasonably, in addition to all other allocations or adjustments that may be required, shall include the portion of the price, if any, that is payable for capacity, which is attributable to that portion of the energy that physically crossed the Manitoba border and was delivered during the Applicable Commissioning Time Period for each of the Applicable Off-Peak Opportunity Transactions in determining the actual average weighted price over the Applicable Commissioning Time Period;~~

~~(d) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Off-Peak Opportunity Transactions shall be adjusted to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable Off-Peak Opportunity Transactions. The charges or credits will include actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement;~~

~~(e) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable Off-Peak Opportunity Transactions shall be determined in Canadian Dollars per MWh and if Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid in U.S. Dollars pursuant to any of the Applicable Off-Peak Opportunity Transactions, the amounts shall be converted to Canadian Dollars (after the adjustments referred to in Section 2.6), by reference to the Equivalent Canadian Dollar Amount on the last Business Day~~

~~of the month, during which the said obligation to pay, or the entitlement to be paid the said amount arises; and~~

~~(f) the Off-Peak Opportunity Transaction Rate shall be expressed in Canadian Dollars per MWh and shall be calculated by dividing (i) the total net amount that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, pursuant to the Applicable Off-Peak Opportunity Transactions, determined in accordance with this Section 2.6; by (ii) the total energy that was imported or exported by Hydro pursuant to the Applicable Off-Peak Opportunity Transactions, determined in accordance with this Section 2.6.~~

~~(2) The monthly amount to be paid to the Limited Partnership shall be calculated as follows:~~

~~(a) Hydro shall provide the Limited Partnership within ten (10) Business Days of the last day of each month during which Commissioning Energy is generated and received by Hydro at the Point of Interconnection with the Off-Peak Opportunity Transaction Rate determined for that month. The amount to be paid for the Commissioning Energy received by Hydro shall be equal to:~~

~~(i) the Off-Peak Opportunity Transaction Rate, determined for that month; multiplied by~~

~~(ii) the Commissioning Energy received by Hydro during that month, as determined pursuant to Section 4.1.~~

~~Hydro shall credit the Limited Partnership with the monthly amount that is to be paid for the Commissioning Energy pursuant to this Section 2.6, on account of the Limited Partnership's indebtedness under the terms of the Construction Agreement and the Limited Partnership shall be entitled to set-off this credit against its indebtedness under the Construction Agreement.~~

~~2.7~~ 2.19 Term.

(~~1~~a) The Term of this Agreement shall ~~become effective on the Construction Start Date and shall continue for a period of twenty-five (25) years from the Final Closing Date unless extended under Section 2.7(2)~~be from April 1, 2013 to March 31, 2038 unless extended or terminated pursuant to the provisions of this Agreement. ~~(2)~~ The Term ~~of this Agreement~~ shall automatically be extended for periods of twenty-five (25) years each~~, prior to the expiry of the Term~~ starting on April 1, 2038 subject to the ~~condition that~~ following conditions being in effect for the period of time for which the Term is to be extended:

(i) Hydro or an Affiliate of Hydro must have an agreement with the Limited Partnership to operate and dispatch the Wuskwatim Project on substantially the same terms and conditions as those contained in the System Operations and Dispatch Agreement, or the Term shall be extended, subject to such amendments to the terms and conditions of this Agreement as Hydro acting reasonably may require if Hydro or an Affiliate of Hydro is not operating and controlling the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station on substantially the same terms and conditions as those contained in the System Operations and Dispatch Agreement or if any other Person is operating and controlling the Wuskwatim Project, including matters related to the dispatch of the Wuskwatim Generating Station; and

(ii) Hydro or an Affiliate of Hydro must have an agreement with the Limited Partnership to maintain and operate the Wuskwatim Project on substantially the same terms and conditions as those contained in the Operations and Maintenance Agreement, or the Term shall be extended, subject to such amendments to the terms and conditions of this Agreement as Hydro acting reasonably may require if Hydro or an Affiliate of Hydro is not operating and maintaining on substantially the same terms and conditions in the Operations and Maintenance Agreement or if any other Person is maintaining and operating the Wuskwatim Project.

(~~3~~b) Upon expiry of ~~the~~a Term or upon the termination of this Agreement, Hydro shall have no future or further obligation to purchase the Net Actual Generation and capacity of the Wuskwatim Generating Station or to make any ~~payment whatsoever~~further payments to the Limited Partnership and except for Hydro's and the Limited Partnership's rights and obligations arising prior to the expiry of the Term, the rights and obligations of the Parties ~~hereunder~~ under this Agreement shall end and the Limited Partnership shall be entitled to sell the energy and capacity of the Wuskwatim Generating Station to another ~~party~~Person. This Agreement shall not be construed to provide a residual value to either the Limited Partnership or Hydro or to any Person, for the right to use or benefit from the Limited Partnership's or Hydro's Property or the Integrated Power System following the expiry of the Term.

ARTICLE III
AFFIRMATIVE COVENANTS

3.1 Covenants.

During the Term of this Agreement~~ and any extension thereof,~~ the Limited Partnership ~~hereby~~ agrees to be bound by and to perform each of the following affirmative obligations:

~~(1) **Design, Engineering, Construction and Commissioning of the Wuskwatim Project**. At the Limited Partnership's sole expense, the Limited Partnership shall engage Hydro under the Construction Agreement to design, engineer, construct, install and commission the Wuskwatim Project in accordance with the provisions of the Construction Agreement, the Interconnection and Operating Agreement and any additional reasonable requirements or criteria of Hydro, communicated by Hydro to the Limited Partnership.~~

(~~2~~a) **Licences**. The Limited Partnership shall seek, obtain, maintain, comply with and as necessary, review and modify from time to time, at the Limited Partnership's sole expense, the Licences.

(~~3~~b) **Maintenance and Operation of the Wuskwatim Project**. The Limited Partnership shall operate, maintain and repair at the Limited Partnership's sole expense, the Wuskwatim Project in accordance with the reasonable guidelines, procedures, decisions, practices and policies of Hydro (or any Affiliate of Hydro) as amended from time to time and communicated by Hydro to the Limited Partnership and in accordance with the provisions of the Limited Partnership Contractual Obligations.

(~~4~~c) **Applicable Reliability Organization and Governmental Authority**. The Limited Partnership shall at the Limited Partnership's sole expense:

~~(a)~~ (i) cooperate to a reasonable extent with Hydro in fulfilling Hydro's duties and obligations (or the duties and obligations of any Affiliate of Hydro) as a participant in the Applicable Reliability Organization and pursuant to the Hydro Contractual Obligations, as amended from time to time in the same manner and to the same extent as Hydro (or any Affiliate of Hydro), as Hydro may advise;

~~(b)~~ (ii) cooperate with and provide in a timely manner any and all information or data required by the Applicable Reliability Organization or by Hydro for the Applicable Reliability Organization and any other necessary approvals related to the Wuskwatim Project, as Hydro may advise;

~~(c)~~ (iii) comply with the Applicable Reliability Organization procedures, decisions and policies, as Hydro may advise;

~~(d)~~ (iv) be bound by those requirements, decisions and policies of the Applicable Reliability Organization, as Hydro may advise, and those Hydro Contractual Obligations as amended from time to time, in the same manner and to the same extent as Hydro (or any Affiliate of Hydro), as Hydro may advise; and

~~(e)~~ (v) reimburse Hydro for actual costs and expenses imposed on Hydro (or any Affiliate of Hydro) by the Applicable Reliability Organization or Government Authority or pursuant to the Hydro Contractual Obligations which are associated with this Agreement or the Wuskwatim Project and any filing fees incurred by Hydro as a result of the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement.

(4d) **Point of Interconnection**. The Limited Partnership shall at the Limited Partnership's sole expense:

~~(a)~~ (i) cooperate with Hydro in maintaining the interconnection of the Wuskwatim Project to the Integrated Power System, and comply with all provisions of the Interconnection and Operating Agreement;

~~(b)~~ (ii) subject to Articles 2.10 to 2.13 of the PDA, modify the design of the Wuskwatim Project at any time in a manner consistent with Hydro's direction to ensure the interconnection and synchronous operation of the Wuskwatim Project with the Integrated Power System will be safe and reliable and will not adversely affect the Integrated Power System or any other utility's system, or services provided to Hydro's customers; and

~~(c)~~ (iii) cause the Net Actual Generation ~~and Commissioning Energy of the Wuskwatim Generating Station~~ to be delivered to Hydro at the Point of Interconnection.

(~~5~~e) **Fines and Penalties**. If fees, levies, fines, penalties, or costs or expenses are assessed against Hydro by any Governmental Authority due to non-compliance by the Limited Partnership of any provision of this Agreement or reasonably attributed to by the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement unless same relates to an Event of Hydro Default, the Limited Partnership shall indemnify and hold Hydro harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Hydro, including claims for indemnity or contribution made by third parties against Hydro.

(~~6~~f) **Taxes and Fees**. Subject to Section 3.1(~~8~~h) the Limited Partnership shall be responsible for and pay all present or future federal, provincial, municipal or other lawful taxes (for greater certainty this does not include any income taxes that may be payable by Hydro), duties, levies or fees, which without limiting the generality of the foregoing shall include any value added tax or similar taxes, imposed directly or indirectly, which are applicable to Hydro or the Limited Partnership or the Wuskwatim Project by reason of the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement without any reimbursement in whole or in part from Hydro or Hydro shall, if such amounts have been paid by it, be entitled to bill the Limited Partnership in accordance with Article VIII and receive payment.

(~~7~~g) **Additional Costs**. If the application of any Laws (including any interpretation thereof) causes Hydro to be liable for additional taxes~~,~~ (for greater certainty this does not include any income taxes that may be payable by Hydro),, fees or assessments ("**Additional Costs**") reasonably attributable to the Parties entering into this Agreement or in respect of the sale by the Limited Partnership and/or the purchase by Hydro of energy and capacity under this Agreement, Hydro may bill the Limited Partnership monthly for such Additional Costs pursuant to Article VIII and receive payment on account of these Additional Costs . These Additional Costs will be calculated so as to place Hydro in the same economic position (considering the timing of the Additional Costs and any expected benefits resulting from said taxes, fees, assessments by third parties) in which it would have been if it had not be liable for the Additional Costs.

(~~8~~h) **Environmental Credits**. The Limited Partnership shall obtain in its own name any and all environmental credits necessary to operate the Wuskwatim Project in compliance with Laws. Hydro acknowledges that any environmental credits will be assets of or credited to the Limited Partnership as applicable, conditional on the value of such environmental credits having not already been included in the Energy ~~Charge~~Calculation.

(~~9~~i) **Dispatch**. The Limited Partnership agrees that the Wuskwatim Generating Station shall at all times be operated and dispatched by Hydro in accordance with the guidelines, procedures, decisions, practices and policies of Hydro's (or any Affiliate of Hydro) as amended from time to time and Hydro's Contractual Obligations as amended from time to time and communicated by Hydro to the Limited Partnership and in accordance with the provisions of the System Operations and Dispatch Agreement, the Interconnection and Operating Agreement and the Operations and Maintenance Agreement.

(~~10) **Fee**. The~~j) **Fee**. Commencing the month following the month in which both the NCN Total Outstandings and the TPC Total Outstandings have been repaid in full the Limited Partnership shall pay Hydro for each month ~~to Hydro~~ a fee equal to ~~three~~thirty-six percent (~~3~~36%) of the Energy ~~Charges to be paid~~ Calculation payable by Hydro for that month in accordance with the provisions this Agreement plus all present or future Federal, Provincial, Municipal or other lawful taxes, (for greater certainty this does not include any income taxes that may be payable by Hydro) duties, levies or fees, which without limiting the generality of the foregoing should include any value added tax or similar taxes, imposed directly or indirectly on Hydro or the Limited Partnership in respect of the fee. This fee is to compensate Hydro for:

~~(a)~~ (i) assuming the risk that the energy purchased pursuant to this Agreement cannot be sold as a Long-Term Transaction;

~~(b)~~ (ii) not requiring the Limited Partnership pursuant to this Agreement to supply a minimum amount of On-Peak Energy;

~~(c)~~ (iii) costs of lost opportunities arising from the utilization of Hydro's transmission tie-line capacity as a consequence of Hydro's purchase of energy and capacity pursuant to this Agreement at the Point of Interconnection; ~~and~~

~~(d)~~ (iv) assuming the transmission risk in Manitoba associated with Hydro's acceptance of the delivery of all of the energy pursuant to this Agreement at the Point of Interconnection for resale at a different delivery point; and

(v) the suspension of marketing and certain other fees that would have otherwise been payable under the terms of the Initial PDA, had it remained in effect, implemented during the period loans are outstanding under the NCN Financing Agreement and the TPC Financing Agreement.

Hydro may bill this fee to the Limited Partnership or set it off against the amount otherwise due to the Limited Partnership pursuant to the provisions of this Agreement.

(~~11~~k) **Records**. The Limited Partnership shall prepare and maintain or cause to be prepared and maintained complete and accurate operating and other records as Hydro may from time to time request, acting reasonably. This shall include all records required by any Applicable Reliability Organization to maintain accredited capacity for the Wuskwatim Generating Station. Without limiting the generality of the foregoing the Limited Partnership shall on written notice from Hydro provide or cause to be provided all documents and information necessary to meet the accreditation requirements for the Wuskwatim Generating Station of any Applicable Reliability Organization during the Term of this Agreement. The Limited Partnership acknowledges that Hydro may release such information and documentation to the Applicable Reliability Organization in respect of any application or maintenance of accredited capacity for the Wuskwatim Generating Station. In addition Hydro shall have access to inspect and test such metering and other recording equipment and operating records as may be required in respect of any accreditation process.

(~~12~~l) **Inspection**. The Limited Partnership shall provide Hydro and its representatives with access to the Wuskwatim Project and the records relating to the Wuskwatim Project including all records required to be prepared and maintained in accordance with Section 3.1(~~12~~k) of this Agreement and Hydro shall be entitled to make and retain copies of all such records. The inspection of the Wuskwatim Project and the review of the records shall not relieve the Limited Partnership of any of its obligations under this Agreement.

3.2 Acknowledgement and Waiver.

The Limited Partnership expressly acknowledges and agrees that the ~~aforesaid~~ covenants in section 3.1 are obligations solely of the Limited Partnership and that while Hydro may be a party to other agreements with the Limited Partnership, in respect of certain matters related to the aforesaid covenants, the Limited Partnership shall be bound by and shall be responsible for the performance of the aforesaid covenants in accordance with the provisions of this Agreement and any breach of the aforesaid covenants shall be an Event of Limited Partnership Default in accordance with the provisions of this Agreement. The Limited Partnership waives any right to:

(a) defend a claim by Hydro that an Event of Limited Partnership Default has occurred under the provisions of this Agreement; or

(b) to claim Hydro contributed to the breach of any provision of this Agreement; or

(c) refuse to make any payment that is required to be made pursuant to the provisions of this Agreement or to not comply with any other provision of this Agreement;

due to or as a result of an act or omission in any way associated with the provisions of the Construction Agreement, the System Operations and Dispatch Agreement, the Operations and Maintenance Agreement or the Interconnection and Operating Agreement, and without restricting the generality of the foregoing would include any breach by Hydro of any provision of those agreements or the supply of services by Hydro or the performance of work by Hydro under the provision of those agreements. The waiver of rights by the Limited Partnership does not extend to any act or omission by Hydro under any of the aforesaid agreements, for which Hydro is found to be liable under those agreements due to Hydro's gross negligence or willful misconduct.

ARTICLE IV
METERING

4.1 Determination of Energy Delivered.

The amount of On-Peak Energy~~,~~ and Off-Peak ~~Energy and Commissioning~~ Energy delivered by the Limited Partnership to the Point of Interconnection and received by Hydro during any particular time period in the Hydro Financial Year, shall for the purposes of this Agreement, including ~~Section 2.2,~~Sections 2.2 and 2.3, be determined to be equal to:

(a) the quantum of energy measured by metering equipment at or near the Point of Interconnection, in accordance with ~~Section 4.2~~Sections 4.3, 4.4, 4.5,4.6 and 4.7 for any particular period of time; reduced by

(b) the Hydro High Voltage Transmission System Energy Losses applicable for that period of time.

4.2 Transmission System Losses

The Hydro High Voltage Transmission System Energy Losses for any particular period in the Hydro Financial Year shall be determined by Hydro and provided to the Limited Partnership within ten (10) Business Days of the last day of the particular period and shall be expressed as a percentage equal to:

(a) the energy generated and delivered to Hydro's High Voltage Transmission System for that particular period of time during that applicable Hydro Financial Year, from all of the hydraulic and thermal electric generation facilities that form part of the Integrated Power System, (which shall be determined by Hydro measuring the generation and delivery of that energy expressed in GWh); less

(b) the energy delivered from the Hydro High Voltage Transmission System, during that particular period of time in the Hydro Financial Year, to other parts of the Integrated Power System, (which shall be determined by Hydro measuring that energy at exit points, selected by Hydro, from the Hydro High Voltage Transmission System, expressed in GWh); divided by

(c) the amount determined in ~~4.1(c).~~4.1.

~~4.2~~ 4.3 Metering ~~Requirements.~~Equipment.

~~(1)~~ Subject to Section ~~4.2(4)~~4.6 Hydro shall provide, install, operate, maintain and own and/or control metering equipment of revenue quality (the "**Hydro Metering Equipment**"), for the Wuskwatim Generating Station at or near the Point of Interconnection the exact location of which shall be determined by Hydro. The Limited Partnership shall reimburse Hydro for all actual costs and expenses incurred by Hydro under this Article IV, including those associated with the operation, maintenance and administration of the Hydro Metering Equipment and the provision of metering data to the Limited Partnership.

4.4 Operation and Maintenance of Metering Equipment

~~(2)~~ The Hydro Metering Equipment shall be installed, calibrated, repaired, replaced, maintained and tested in accordance with the provisions of the *Electricity and Gas Inspection* Act (Canada) as amended from time to time and any reasonable guidelines, procedures, decisions, practices and policies of Hydro. The Limited Partnership shall provide and maintain without charge, convenient, accessible and safe space at or near the metering point for Hydro Metering Equipment, which shall be in the care of and at the risk of the Limited Partnership. Unless Hydro shall otherwise advise the Limited Partnership, Hydro shall in accordance with any guidelines, procedures, decisions, practices and ~~polices~~policies of Hydro read the meters and supply such meter readings to the Limited Partnership no later than the end of the third Business

Day of each month. Metering records shall be available at all reasonable times to the Limited Partnership.

4.5 Hydro Access to and Testing of Metering Equipment

~~(3)~~ Authorized employees and agents of Hydro shall at reasonable times have free and uninterrupted access to the Wuskwatim Project for the purpose of reading and conducting tests on the Hydro Metering Equipment. Hydro may test, calibrate, maintain, remove and replace the Hydro Metering Equipment at any time. Hydro shall at the Limited Partnership's expense, inspect and test the Hydro Metering Equipment upon installation and at least once every two (2) years, thereafter. If requested to do so by the Limited Partnership, Hydro shall inspect or test metering equipment more frequently than every two (2) years. Hydro shall give reasonable notice of the time when any inspection or test shall take place, and the Limited Partnership may have representatives present at the test or inspection. Unless provided otherwise by the *Electricity and Gas Inspection Act* (Canada) or other Laws, if Hydro Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at the Limited Partnership's expense, in order to provide accurate metering. If Hydro Metering Equipment fails to register, or if the measurement made by Hydro Metering Equipment during a test varies by more than one percent (1%) from the measurement made by the standard meter used in the test, adjustment shall be made correcting all measurements made by the inaccurate meter for (i) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (ii) the period immediately preceding the test of the Hydro Metering Equipment equal to one-half the time period from the date of the last test of the Hydro Metering Equipment provided that the period covered by the correction shall not exceed six months. Hydro shall provide copies of its metering tests to the Limited Partnership, which shall provide the information to TPC at least biannually.

4.6 Alternate Metering Equipment.

~~(4)~~ Hydro may on notice to the Limited Partnership advise that it shall not install its own metering equipment in accordance with the provisions of Sections ~~4.2(1), (2)~~4.3, 4.4 and ~~(3~~4.5) and shall for the purposes of ~~Section 4.1,~~Sections 4.1 and 4.2, have the quantum of energy determined by the metering equipment installed, operated, maintained, owned and/or controlled by Hydro (Transmission and Development Business Unit) pursuant to the provisions of the

Interconnection and Operating Agreement. The Parties agree that in the event Hydro provides this notice that the metering data provided to the Limited Partnership pursuant to the provisions of the Interconnection and Operating Agreement shall be used for the purposes of determining the quantum of energy delivered to the Point of Interconnection.

4.7 IOA Inspections and Testing

The Parties also agree to be bound by the inspection and testing provisions of the Interconnection and Operating Agreement and to any adjustments or corrections that are made in accordance with the provisions of that agreement to the metering measurements and data and Hydro shall be entitled to receive all metering data and records that the Limited Partnership receives pursuant to the provisions of the Interconnection and Operating Agreement. Hydro shall also be entitled to attend with the Limited Partnership at all testing of the metering equipment under the provisions of the Interconnection and Operating Agreement. The Limited Partnership agrees to cause the metering equipment to be inspected or tested in accordance with the provisions of the Interconnection and Operating Agreement if Hydro so requests. Hydro shall retain its right on reasonable notice to the Limited Partnership to install the Hydro Metering Equipment in accordance with Sections ~~4.2(1), (2)~~4.3, 4.4 and ~~(3)~~4.5 at a subsequent date and to have those provisions apply for the determination of the quantum of energy delivered to the Point of Interconnection.

ARTICLE V
ENERGY RATE ADJUSTMENTS

5.1 Report on Long-Term Transactions and Opportunity Transactions.

Hydro shall provide the Limited Partnership within thirty (30) days of the last day of each Hydro Financial Year with a written report of the amount of energy (expressed in GWh) that was bought or sold pursuant to the Long-Term Transactions that were used to calculate the Long-Term Transaction Rate for that Hydro Financial Year and the amount of energy (expressed in GWh) that was bought or sold pursuant to the Opportunity Transactions that were used to calculate the Opportunity Transaction Rate for that Hydro Financial Year. Such report shall also include particulars of the ~~determinations, allocations or adjustments (the "~~Adjustments~~")~~ made by Hydro pursuant to ~~Sections 2.2(1)(c), (d), and (e) and 2.2(3)(c), (d) and (e) respectively.~~Section 2.4

5.2 Insufficient Transaction in Respect of Long-Term Transaction Rate.

If the report prepared by Hydro pursuant to Section 5.1 in respect of a particular Hydro Financial Year discloses there were Insufficient Transactions in respect of the Long-Term Transaction Rate for that Hydro Financial Year, then, subject to an Energy Rate Review brought pursuant to Article XVII of the PDA the compensation to be paid by Hydro for the On-Peak Energy received by Hydro at the Point of Interconnection on a Canadian Dollar per MWh basis during that Hydro Financial Year (the "**Insufficient Long-Term Transaction Year**") shall be based on a rate that is equal to the actual weighted average price over the Insufficient Long-Term Transaction Year that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid, for the energy and capacity purchased or sold by Hydro pursuant to all applicable On-Peak Opportunity Transactions during the Insufficient Long-Term Transaction Year (the "**On-Peak Opportunity Transaction Rate**") determined in the following manner:

(a) only those On-Peak Opportunity Transactions or portions thereof applicable to the time period where the energy sold or purchased physically crossed the Manitoba border and were delivered during the Insufficient Long-Term Transaction Year, as determined by Hydro in accordance with Good Utility Practice, (the "**Applicable On-Peak Opportunity Transactions**") shall be included in determining the actual weighted average price over the Insufficient Long-Term Transaction Year;

(b) Hydro, acting reasonably, in addition to all other allocations or adjustments that may be required, shall include the portion of the price, if any, that is payable for capacity, which is attributable to that portion of the energy that physically crossed the Manitoba border and was delivered during the Insufficient Long-Term Transaction Year for each of the Applicable On-Peak Opportunity Transactions in determining the actual average weighted price over the Insufficient Long-Term Transaction Year;

(c) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable On-Peak Opportunity Transactions shall be adjusted to reflect the price at the Manitoba border, net of all charges or credits applicable to or allocated by Hydro, acting reasonably to the Applicable On-Peak Opportunity Transactions. The charges or credits will include actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but shall not include Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement;

(d) the actual price that Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid pursuant to the Applicable On-Peak Opportunity Transactions shall be determined in Canadian Dollars per MWh and if Hydro, as purchaser is obligated to pay or Hydro, as seller is entitled to be paid in U.S. Dollars pursuant to any of the Applicable On-Peak Opportunity Transactions, the amounts shall be converted to Canadian Dollars (after the ~~adjustments~~Adjustments referred to in ~~this~~ Section ~~5.2~~2.4) by reference to the average Equivalent Canadian Dollar Amount ~~on the last Business Day of~~for the month, during which the said obligation to pay, or the entitlement to be paid the said amount arises; and

(e) the On-Peak Opportunity Transaction Rate shall be expressed in Canadian dollars per MWh and shall be calculated by dividing (i) the total net amount that Hydro, as purchaser, is obligated to pay or Hydro, as seller, is entitled to be paid, pursuant to the Applicable On-Peak Opportunity Transactions, determined in accordance with this Section 5.2; by (ii) the total energy that was imported or exported by Hydro pursuant to the Applicable On-Peak Opportunity Transactions, determined in accordance with this Section 5.2.

If as a result of an Energy Rate Review ~~brought~~ pursuant to Article XVII of the PDA, the compensation to be paid by Hydro for the On-Peak Energy received by Hydro during the Insufficient Long-Term Transaction Year is greater than or less than the compensation determined in accordance with this Section 5.2, then Hydro shall prepare a reconciliation of the amount owing to the Limited Partnership by Hydro or that Hydro has overpaid. The reconciliation shall adjust for all amounts that the Limited Partnership is required to pay to

Hydro, that is based on or is otherwise determined from the Energy ~~Charge~~Calculation paid by Hydro to the Limited Partnership for the delivery of the Net Actual Generation, including the fee to be paid pursuant to Section 3.1(~~11~~j). On completion of the reconciliation any amount overpaid by Hydro, shall immediately be paid by the Limited Partnership to Hydro, without interest, unless Hydro agrees in writing to receive same as a credit on account of any amount otherwise required to be paid pursuant to the provisions of this Agreement and any additional amount owing by Hydro shall immediately be paid by Hydro to the Limited Partnership without interest.

5.3 Insufficient Transactions in Respect of the Opportunity Transaction Rate.

If the report prepared by Hydro pursuant to Section 5.1 in respect of a particular Hydro Financial Year discloses there were Insufficient Transactions in respect of the Opportunity Transaction Rate for that Hydro Financial Year, then, the compensation to be paid by Hydro for the Off-Peak Energy received by Hydro during that Hydro Financial Year and for all subsequent years shall, subject to any future Energy Rate Review, be determined pursuant to the Energy Rate Review, brought pursuant to Article XVII of the PDA.

5.4 Adjustment of Energy Rate.

The Energy Rate payable under this Agreement shall be adjusted to accord with the agreement of the Parties or the decision of an Expert made pursuant to an Energy Rate Review and Transaction Rate Review. Forthwith after any agreement or decision which has retroactive effect, Hydro shall prepare a reconciliation of the amount that is owing to the Limited Partnership by Hydro or the amount that Hydro has overpaid. The reconciliation shall adjust for all amounts that the Limited partnership is required to pay to Hydro, that is based on or is otherwise determined from the Energy ~~Charge~~Calculation paid by Hydro to the Limited Partnership adjust for all amounts that the Limited partnership is required to pay to Hydro, that is based on or is otherwise determined from the Energy Calculation paid by Hydro to the Limited Partnership for the delivery of the Net Actual Generation, including the fee required to be paid pursuant to Section 3.1(~~11~~j). On completion of the reconciliation any amount overpaid by Hydro, shall immediately be paid by the Limited Partnership to Hydro, without interest, unless Hydro agrees in writing to receive same as a credit on account of any amount otherwise required to be paid to the Limited Partnership pursuant to the provisions of this Agreement and any additional amount owing by Hydro shall immediately be paid by Hydro to the Limited Partnership without interest.

ARTICLE VI
ENERGY RATE REVIEWS AND TRANSACTION RATE REVIEWS

6.1 Energy Rate Review.

The Long-Term Transaction Rate and the Opportunity Transaction Rate used to determine the Energy Rate have been agreed to as a proxy or reasonable substitute to capture the enhanced value of the energy and capacity to Hydro in the electricity markets available to Hydro outside of Manitoba and the recovery of associated costs related to the purchase of the energy and capacity from the Limited Partnership and the resale in the electricity markets available to Hydro outside of Manitoba. The Energy Rate has been arrived at based on industry practices existing as at the date of this Agreement for the pricing of different types of transactions for different classes or categories of energy. Industry practices may change during the Term, possibly significantly. For this reason, the Pricing ~~Principle~~Principles and Pricing Criteria described in Sections 6.2 and 6.3 have been established to ~~govern~~ apply to any Energy Rate Review. Subject to Sections 6.2 and 6.3, the Energy Rate may be reviewed from time to time in the manner provided in Article XVII of the PDA.

~~6.2~~ 6.2 Pricing ~~Principle~~Principles.

~~The pricing principle set forth below (the "**Pricing Principle**") shall govern any Energy Rate Review:~~

~~(a) the~~The rate Hydro is to pay for the capacity, of and the energy generated by, the Wuskwatim Project will be based on the value of the energy and capacity to Hydro at the Manitoba border in the electricity markets available to Hydro outside of Manitoba. During the ten year period from 2014/15 to 2023/24, the Domestic Transaction Rate will form a portion of the rate Hydro will pay the Limited Partnership. In the years after the NCN Total Outstandings and TPC Total Outstandings are repaid in full, the Fee will be implemented in place of all fees that would have been payable under the terms of the Initial PPA had it remained in effect.

These principles shall be collectively known as "the **Pricing Principles**" for purposes of any Rate Review.

~~6.3~~ 6.3 Pricing Criteria.

~~In the application of the Pricing Principle, during~~During an Energy Rate Review the following pricing criteria (the "**Pricing Criteria**") shall be ~~applied~~applicable:

(a) the rate will recognize: (i) the effects of ~~the~~ applicable constraints and regulations that may limit access to the electricity markets outside of Manitoba; and (ii) any other risks or actual costs to Hydro, associated with or applicable to the purchase of the energy and capacity of the Wuskwatim Project from the Limited Partnership and the resale of that energy and capacity in ~~the~~ electricity markets outside of Manitoba (to the extent Hydro has not been compensated for these risks or costs pursuant to other provisions of this Agreement);

(b) in determining the value of the energy and capacity of the Wuskwatim Project the rate will recognize that the Wuskwatim Project is operated by Hydro as part of the Integrated Power System and although Hydro, as purchaser, accepts the energy from the Wuskwatim Project as it is produced on an hourly basis, Hydro through its operation of the Integrated Power System is able to allocate portions of the energy into other time periods;

(c) if Hydro is exporting or importing energy to or from electricity markets outside of Manitoba in reasonable quantities (the determination of which is not restricted by the quantum referenced for Insufficient Transactions), the price that Hydro obtained at the Manitoba border for the export or import of the energy that physically crossed the Manitoba border pursuant to the export or import transactions ~~(net of all charges or credits associated with or applicable to those transactions including actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but not including Hydro's administrative and general overhead costs and expenses or any costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement) will be used when determining the~~

~~value of the energy and capacity of the Wuskwatim Project to Hydro~~net of all Adjustments ; and

(d) if Hydro is not exporting or importing energy and capacity in reasonable quantities (the determination of which is not restricted by the quantum referenced for Insufficient Transactions), then, subject to Section 6.3(a)(ii), the determination of value to Hydro will be made based on the price that Hydro could have obtained at the Manitoba border if it was exporting energy and capacity to electricity markets available to Hydro outside of Manitoba ~~(net of all charges or credits associated with or applicable to those transactions including actual costs and expenses that Hydro has incurred which were reasonably necessary to provide access to the export markets or to facilitate Hydro entering into export transactions but not including Hydro's administrative and general overhead costs and expenses or any other costs or expenses that Hydro has been reimbursed for, pursuant to other provisions of this Agreement).~~net of all Adjustments.

~~6.4~~ 6.4 Transaction Rate Review.

The Adjustments made by Hydro ~~pursuant to Sections 2.2(1)(c), (d) and (e) and 2.2(3)(c), (d) and (e), as the case maybe,~~ may be reviewed in the manner provided in Article XVII of the PDA.

ARTICLE VII
REPRESENTATIONS AND WARRANTIES

7.1 Representations and Warranties of the Limited Partnership.

The Limited Partnership ~~hereby~~ represents and warrants that each of the following representations and warranties is true and ~~correct~~accurate:

(a) the Limited Partnership is a limited partnership duly formed, validly existing and in good standing under the laws of the Province of Manitoba and has all requisite power and authority to own, operate or lease the properties owned or to be owned, operated or leased by the Limited Partnership and to carry on its business as contemplated by the Limited Partnership Agreement; and

(b) this Agreement has been duly authorized, executed and delivered by the General Partner by or on behalf of the Limited Partnership and is a legal, valid and binding obligation of the Limited Partnership and of the General Partner enforceable against each of them by Hydro in accordance with its terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or by this Agreement, at the discretion of the Arbitrator.

7.2 Survival of Representations and Warranties of the Limited Partnership.

All the representations and warranties of the Limited Partnership ~~contained~~ in Section 7.1 shall survive the execution and delivery of this Agreement and shall continue in full force and effect notwithstanding any investigation made at any time by or on behalf of Hydro.

7.3 No Representations by the Limited Partnership.

No other representation, warranty or other statement made by the Limited Partnership in respect of this Agreement shall be binding on the Limited Partnership unless made by it in writing as a specific amendment to this Agreement.

7.4 Representations and Warranties of Hydro.

Hydro ~~hereby~~ represents and warrants that each of the following representations and warranties is true and ~~correct~~accurate:

(a) Hydro is a corporation duly incorporated and organized and validly subsisting under the laws of the Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and to perform its obligations hereunder, subject to the provisions of the *Hydro Act*; and

(b) this Agreement has been duly authorized, executed and delivered by Hydro and is a legal, valid and binding obligation of Hydro enforceable against Hydro by the Limited Partnership in accordance with its terms, except as enforcement may be limited by the provisions of the *Hydro Act* and by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or, by this Agreement, at the discretion of the Arbitrator.

7.5 Survival Representations and Warranties of Hydro.

All the representations and warranties of Hydro contained in Section 7.4 shall survive the execution of this Agreement and shall remain in full force and effect notwithstanding any investigation made at any time by or on behalf of the Limited Partnership.

7.6 No Representations by Hydro.

No other representation, warranty or other statement made by Hydro in respect of this Agreement shall be binding on Hydro unless made by it in writing as a specific amendment to this Agreement.

ARTICLE VIII
BILLING, PAYMENTS AND ADJUSTMENTS

8.1 ~~Billing~~Billings, Payments and Adjustments~~.~~

(1) All billings shall be calculated monthly at the end of each calendar month and reconciled monthly and yearly in accordance with provisions of this Agreement.

(2) ~~All bills shall be delivered monthly by the~~ The Limited Partnership shall deliver all bills to Hydro~~. Bills shall be delivered~~ monthly within twenty-one (21) calendar days after the end of the period covered by ~~such~~ the bill. The period for billing shall be from 12:01 a.m. (Winnipeg time) of the first calendar day of the month to 12:01 a.m. (Winnipeg time) of the first calendar day of the succeeding month~~.~~ Bills shall be ~~deemed~~ considered rendered upon receipt by Hydro. If all information necessary is not accurately known in time for the preparation of the monthly bill, estimates may be used to prepare an interim bill with a final bill to be prepared when accurate information becomes known.

(3) All bills shall be due and payable in immediately available same-day funds within five (5) Business Days from the date the bill is rendered. If such due date falls on a non -Business

Day, the payment shall be due and payable on the next following Business Day. Payments received after the due date shall be considered late. Late payments shall include a fee equal to the amount determined by applying interest at the prime rate established by the Limited Partnership's bank plus two percent (2%) per annum to the overdue amount billed for the period the payment is late.

(4) If a Party disputes all or any part of a bill, that Party shall pay the amount of the bill not in dispute to the other Party and shall pay into an account specified by Hydro that portion of the bill in dispute, pending resolution of such dispute. If the resolution of a dispute regarding a bill results in a refund, interest thereon shall accrue at whatever rate of interest is applicable to the account into which the disputed amount has been deposited.

(5) Payment of all bills shall be made by interbank wire transfer to the Limited Partnership bank in accordance with the account instructions as provided by the Limited Partnership and payment shall be deemed made when received by the designated bank.

(6) Hydro shall bill the Limited Partnership for all actual costs and expenses which it incurs in connection with this Agreement. The Limited Partnership's payment to Hydro under this paragraph shall be made within five (5) Business days following receipt of the written bill from Hydro. Payments made after the due date shall be considered late and shall bear interest on the unpaid balance at an annual rate of the Limited Partnership's bank's prime interest rate plus two percent (2%) per annum.

(7) Hydro shall have the right to set-off and/or recoup against payments to be made to the Limited Partnership by the terms of this Agreement any amount reasonably believed by Hydro to be due to Hydro from the Limited Partnership under Section 3.1(~~11~~j) and under Section 9.3(b). Hydro's exercise of its right of retention under this section is without prejudice to the Limited Partnership's right to contest the set-off and the claim upon which the set-off is based. Where Hydro exercises its right of set-off or recoupment, Hydro shall notify the Limited Partnership in writing of the specific basis for the set-off or recoupment in reasonable detail, including the basis for calculation of the amount believed to be due to Hydro.

ARTICLE IX

SPILL ENERGY REVENUE ADJUSTMENT

9.1 Article IX Definitions.

For purposes of this Article IX, defined terms shall have the following meanings:

"**Average On-Peak Energy Price**" means the average Energy Rate paid by Hydro to the Limited Partnership for On-Peak Energy, calculated on an annual basis, pursuant to this Agreement for a particular Hydro Financial Year less:

(a) Transmission Costs;

(b) the Fee, if applicable; and

(c) Water Rental Charges.

"**Average Off-Peak Energy Price**" means the average Energy Rate paid by Hydro to the Limited Partnership for Off-Peak Energy, calculated on an annual basis, pursuant to this Agreement for a particular Hydro Financial Year less:

(a) Transmission Costs;

(b) the Fee, if applicable; and

(c) Water Rental Charges.

"**CRD**" means the diversion of water from the Churchill River to the Nelson River and the impoundment of water on the Rat River and Southern Indian Lake as authorized by the CRD Licence;

"**CRD Licence**" means the interim or final licence and associated approvals to operate the CRD granted from time to time by Manitoba to Hydro under *The Water Power Act* (Manitoba);

"**CRD Wuskwatim Spill Energy**" means the total energy in GWh that could have been generated at the Wuskwatim Generating Station within each Hydro Financial Year as On-Peak

Spill Energy and as Off-Peak Spill Energy, respectively, had excess water not been spilled at Missi Falls calculated in accordance with Section 9.2.

"**Fee**" means the fees payable by the Limited Partnership to Hydro under Section 3.1(j) of this Agreement.

"**Missi Falls**" means the Missi Falls Control Station operated by Hydro.

"**Missi Falls Minimum Flow**" means the minimum discharge requirement as specified in the licences issued to Hydro for Missi Falls under the CRD Licence or other licence, permit or regulatory provisions applicable to the operation of Missi Falls from time to time.

"**Notigi**" means the Notigi Control Station operated by Hydro.

"**Notigi Maximum Flow**" means the maximum discharge requirement as specified in the licences issued to Hydro for Notigi under the CRD Licence or other licence, permit or regulatory provisions applicable to the operation of Notigi from time to time.

"**Off-Peak Spill Energy**" means that portion of CRD Wuskwatim Spill Energy, measured in MWh, that would have been generated as Off-Peak Energy minus 1.73 GWh or such other amount of energy to be deducted as determined in a Rate Review.

"**On-Peak Spill Energy**" means that portion of CRD Wuskwatim Spill Energy, measured in MWh, that would have been generated as On-Peak Energy minus 0.87 GWh or such other amount of energy to be deducted as determined in a Rate Review.

"**Spill Energy Revenue Adjustment**" means the amount calculated pursuant to Section 9.3.

"**SPLASH Modelling**" means the results Hydro generated as at the Hydro Financial Year ending on March 31, 2005 under its computer model (Simulation Program for Long-term Analysis of System Hydraulics) to simulate the operation of the Integrated Power System under a series of flow conditions with the objective of meeting a forecast of load requirements and maximizing revenues while recognizing limitations imposed by licences and agreements.

"**Transmission Costs**" means costs related to the transmission of Net Actual Generation received by Hydro at the Point of Interconnection on the Hydro Transmission System.

"**Water Rental Charges**" means the Water Rental charges payable to the Province of Manitoba, under *The Water Power Act* (Manitoba), for use of water for the Wuskwatim Project.

"**Wuskwatim GS Spill**" means a spill or release of water at the Wuskwatim Project as a result of operating conditions.

9.2 CRD Wuskwatim Spill Energy Calculation.

The CRD Wuskwatim Spill Energy shall be the sum of the On-Peak Spill Energy and the Off-Peak Spill Energy and shall be determined:

(a) based on an amount of water flow equal to the lesser of:

(i) Missi Falls flow in excess of the Missi Falls Minimum Flow; if the value is less than zero, the value shall equal zero;

(ii) Notigi Maximum Flow in effect at the time minus the actual Notigi flow, if the value is less than zero, the value shall equal zero;

(iii) zero during any period during which a Wuskwatim GS Spill occurs; and

(iv) zero during any period in which Hydro is unable to accept energy generated at the Wuskwatim Generating Station due to domestic transmission constraints per Section 2.18 of this Agreement;

(b) with allowance for:

(i) Missi Falls flow in excess of the Missi Falls Minimum Flow considered necessary by Hydro, acting in accordance with Good Utility Practice, to manage wind effects, ice formation, emergency conditions, control structure manual operability constraints, or other relevant factors; and

(ii) Notigi flow below Notigi Maximum Flow considered necessary by Hydro, acting in accordance with Good Utility Practice, to manage wind effects, operation to manage ice formation, emergency conditions, control structure manual operability constraints, all other relevant factors;

(c) provided that if Wuskwatim generation units are out of service or derated, the calculation of CRD Wuskwatim Spill Energy shall be reduced by the amount of energy that potentially could have been generated if generation units were not out of service or derated.

9.3 Revenue Adjustment Calculation.

Within one hundred twenty (120) days of the end of each Hydro Financial Year, commencing in the Hydro Financial Year ending March 31, 2015, Hydro shall provide the Limited Partnership and the Limited Partners with a calculation of the CRD Wuskwatim Spill Energy and the following information:

(a) the CRD Wuskwatim Spill Energy for the immediately preceding Hydro Financial Year;

(b) the particulars of the calculation of the CRD Wuskwatim Spill Energy, the Average On-Peak Energy Price, the Average Off-Peak Energy Price, the On-Peak Spill Energy Amount, if any, and the Off-Peak Spill Energy Amount, if any, for that Hydro Fiscal Year; and

(c) the data and methodologies which formed the basis of the calculations, in reasonable detail so each Limited Partner can verify the calculations.

9.4 Payment of Revenue Adjustment.

Within thirty (30) days of providing the information in Section 9.3:

(a) if the CRD Wuskwatim Spill Energy is a number greater than zero, Hydro shall pay to the Limited Partnership an amount equal to the sum of:

(i) the product of the On-Peak Spill Energy and the Average On-Peak Energy Price; and

(ii) the product of the Off-Peak Spill Energy and the Average Off-Peak Energy Price.

(b) if the CRD Wuskwatim Spill Energy is a number less than zero, the Limited Partnership shall pay to Hydro an amount equal to the sum of:

(i) the product of the On-Peak Spill Energy Amount, negative one (-1.0), and the Average On-Peak Energy Price; and

(ii) the product of the Off-Peak Spill Energy, negative one (-1.0), and the Average Off-Peak Energy Price.

Hydro may set-off any amount payable by the Limited Partnership pursuant to Section 9.4 against any amounts Hydro is obligated to pay the Limited Partnership pursuant to this Agreement.

9.5 Spill Energy Amount and Revenue Adjustment Review.

The Parties agree that the CRD Wuskwatim Spill Energy and the data and methodologies which formed the basis of the calculations used in determining the Spill Energy Revenue Adjustment may be reviewed from time to time in the manner provided for in Article XVII of the PDA. The Parties agree that the principles to be considered in a Rate Review of the CRD Wuskwatim Spill Energy and the Spill Energy Revenue Adjustment are that:

(a) the Parties intend the Limited Partnership receives or pays an annual adjustment that would make the annual total revenue of the Limited Partnership equal to that which it would have received if the CRD Wuskwatim Spill Energy equaled the average amount of spill energy predicted by the SPLASH Modelling for Hydro's Financial Year ending March 31, 2005; and

(b) the Fee and the Water Rental Charges in effect at the date of each adjustment shall be subtracted from the amount of the adjustment.

ARTICLE X~~ARTICLE IX~~

EVENTS OF DEFAULT

10.1 ~~9.1~~ Event of Limited Partnership Default

If any of the following events, conditions or circumstances (each an "**Event of Limited Partnership Default**") shall occur and be continuing~~:~~, then Hydro by written notice to the Limited Partnership shall be entitled to terminate the obligations of Hydro under this Agreement:

(1) any representation or warranty or certification made or deemed to be made by the Limited Partnership pursuant to or in connection with this Agreement delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(2) an Arbitrator makes a determination that the Limited Partnership failed to perform or observe any term, covenant or agreement contained in this Agreement, on its part to be performed or observed and such failure shall remain unremedied after the end of the period within which the Arbitrator determines the Limited Partnership is required to remedy such failure;

(3) (the Limited Partnership shall:

(a) become insolvent or generally not pay its debts as such debts become due;

(b) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(c) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(d) institute or have instituted against it any proceeding seeking:

(i) to adjudicate it a bankrupt or insolvent;

(ii) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iii) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of the Limited Partnership's Property;

(iv) and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within 30 days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of the Limited Partnership's Property) shall occur; or

(v) take any action to authorize any of the foregoing actions;

(4) Notice is sent to or received by the Limited Partnership from any creditor with respect to the intention of such creditor to enforce a lien on any Property of the Limited Partnership unless such Notice is being contested in good faith by appropriate legal proceedings and such Notice has not resulted in, or does not involve, any immediate danger of the sale, forfeiture or loss of any of the Property of the Limited Partnership that is the subject of such Notice;

(5) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Authority which may be reasonably likely to require the Limited Partnership to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against the Limited Partnership, and either:

(a) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

(b) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(6) the loss, suspension or failure to renew any Licence or any other licence or permit held by the Limited Partnership or any agreement to which the Limited Partnership is a party the effect of which would prohibit or otherwise restrict the Limited Partnership from conducting all or a material part of the Business; or

(7) the occurrence of a Material Adverse Business Effect~~;then, and in any such event, Hydro shall by written notice to the Limited Partnership be entitled to terminate the obligations of Hydro under this Agreement~~.

10.2 ~~9.2~~ Expense of Hydro

Upon the occurrence of any Event of Limited Partnership Default, which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Limited Partnership Default. All reasonable expenses and costs, charges incurred by or on behalf of Hydro in connection with any remedial action taken pursuant to this Section ~~9.2~~10.2 shall be a cost to be paid to Hydro by the Limited Partnership in accordance with provisions of this Agreement.

10.3 ~~9.3~~ Event of Hydro Default

If any of the following events, conditions or circumstances (each an "**Event of Hydro Default**") shall occur and be continuing then the Limited Partnership by written notice to Hydro shall be entitled to terminate the obligations of the Limited Partnership under this Agreement:

(1) an Arbitrator makes a determination that Hydro failed to perform or observe any term, covenant or agreement contained in this Agreement on its part to

be performed or observed and such failure shall remain unremedied after the end of the period within which the Arbitrator determines Hydro is required to remedy such failure; or

(2) Hydro shall:

(a) become insolvent or generally not pay its debts as such debts become due;

(b) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(c) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(d) institute or have instituted against it any proceeding seeking:

(i) to adjudicate it a bankrupt or insolvent;

(ii) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors; or

(iii) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property;

(iv) and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within 30 days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; or

(v) take any corporate action to authorize any of the foregoing actions;

then, in any such event, the Limited Partnership shall by written notice to Hydro be entitled to terminate the obligations of the Limited Partnership under this Agreement.

10.4 ~~9.4~~ Expense of the Limited Partnership

Upon the occurrence of any Event of Hydro Default, which has not been waived and is continuing, the Limited Partnership may take any action the Limited Partnership considers advisable, acting reasonably, to remedy the effect of such Event of Hydro Default. All reasonable expenses and costs, charges incurred by or on behalf of the Limited Partnership in connection with any remedial action taken pursuant to this Section 9.4 shall be a cost to be paid to the Limited Partnership by Hydro in accordance with provisions of this Agreement.

10.5 ~~9.5~~ Remedies Cumulative

The remedies provided for in this Agreement are cumulative and do not exclude any other right or remedy provided by Law.

ARTICLE XI~~ARTICLE X~~

DISPUTE RESOLUTION

11.1 ~~10.1~~ General.

Subject to Section ~~10.2,~~11.2, all disputes, differences or claims, or apprehended disputes or claims which arise under this Agreement relating to the application, interpretation, meaning, alleged violation, performance or non-performance of this Agreement shall be settled by final and binding arbitration conducted pursuant to the provisions of this Article ~~X~~XI.

11.2 ~~10.2~~ Limitation.

The provisions of this Article ~~X~~XI do not apply to ~~an Energy~~a Rate Review ~~or Transaction Rate Review,~~ which reviews shall be conducted pursuant to the provisions of Article XVII of the PDA. Notwithstanding the provisions of this Article ~~X~~XI an Arbitrator appointed pursuant to this Article ~~X~~XI shall have no jurisdiction to consider or review any matters referred to or referable to an Expert under Article XVII of the PDA, except with respect to the enforcement of a decision of such Expert made in accordance with the provisions of Article XVII of the PDA.

11.3 ~~10.3~~ Endeavour to Resolve.

The Parties agree that prior to bringing any dispute, difference or claim to arbitration pursuant to the provisions of this Article ~~X~~XI, they shall use reasonable efforts to resolve such dispute, difference or claim amongst themselves.

11.4 ~~10.4~~ Arbitration.

A Party (an "**Applicant**") who wants to settle a dispute~~,~~ difference or claim or apprehended dispute, difference or claim referred to in Section ~~10.1~~11.1 (a "**Dispute**")) shall provide the other Party a written notice (a "**Dispute Notice**") which shall contain the following:

(a) the name of the respondent and interested parties;

(b) a detailed description of the Dispute; and

(c) the relief, remedy, redress or declaratory order sought.

A Dispute Notice shall be delivered within 180 days from when the Applicant knew or reasonably ought to have known of the existence of a Dispute, subject to the written agreement of the Parties to extend this time limit. An Applicant who fails to deliver a Dispute Notice with respect to a Dispute within the prescribed period shall be deemed to have waived and abandoned the Dispute.

11.5 ~~10.5~~ Reply.

The Party who receives a Dispute Notice (a "**Respondent**") shall, within 60 days of receiving the Dispute Notice, provide the Applicant with a written reply (a "**Reply**"), which sets out in detail the Respondent's position with respect to the Dispute.

11.6 ~~10.6~~ Referral to Arbitration.

Within 30 days of the Applicant's receipt of the Reply, if the Dispute has not been settled, the Dispute shall be referred to binding arbitration pursuant to the provisions of *The Arbitration Act*

(Manitoba) and the following sections of this Article ~~X~~XI, provided that if there is any inconsistency between the provisions of the said Act and ~~the said sections, the provisions of the said sections shall prevail.~~Section 11, this Agreement shall apply.

11.7 ~~10.7~~ Appointment of Arbitrator.

Subject to Section ~~10.8,~~11.8, an Arbitrator shall be appointed to adjudicate the dispute, using the following procedure:

(1) the Applicant shall provide to the Respondent and the Respondent shall provide to the Applicant the names, addresses and occupations of not more than three individuals, each of whom it would accept as an Arbitrator;

(2) if any one of the persons on the list of proposed arbitrators is acceptable to the Applicant and the Respondent and is willing and able to act as the Arbitrator, then that person shall be appointed as the Arbitrator forthwith; and

(3) if within 45 days of the referral of the Dispute to the binding arbitration the Applicant and the Respondent cannot agree upon a person to act as Arbitrator, either of them may request that the Arbitrator be appointed by the Chief Justice or the Associate Chief Justice of the Court of Queen's Bench (Winnipeg Division) by application to the said court served on the other Party to the arbitration.

11.8 ~~10.8~~ Qualifications of Arbitrator.

An Arbitrator appointed pursuant to Section ~~10.7~~11.7 shall:

(a) be qualified to decide the particular question in dispute;

(b) not have a pecuniary interest in the particular matter in dispute; and

(c) not have, within a period of one year prior to the date on which the matter was referred to arbitration pursuant to Section ~~10.4,~~11.4, acted, or been a member of any firm that has acted as solicitor, counsel or agent for any of the Parties.

11.9 ~~10.9~~ Length of Hearing.

The Arbitrator once appointed shall proceed expeditiously to hear and determine the question or questions in dispute as set out in the Dispute and Reply, subject to any reasonable delay due to, or resulting from, any unforeseen circumstances.

11.10 ~~10.10~~ Place of Hearing.

The arbitration shall take place at such location, place and time as the Parties may agree or as the Arbitrator shall fix. The law applicable to the arbitration shall be the Laws of Manitoba and the Laws of Canada applicable in Manitoba.

11.11 ~~10.11~~ Powers of the Arbitrator.

The Arbitrator may determine all questions of law, fact and jurisdiction and all matters of procedure relating to the arbitration. The Arbitrator shall have the right to grant all legal and equitable relief necessary to provide a final and conclusive resolution of the Dispute including, without limitation, the right to relieve, on just and equitable terms, if applicable, against breaches of time limits set out in this Agreement, the right to determine, if applicable, the monetary value of any loss or injury suffered by a Party and to make an order directing a Party to pay the monetary value of any loss or injury so determined and to award costs (including legal fees and the costs of the arbitration) and interest. Except as the Parties otherwise expressly agree, the Arbitrator shall not have the authority or jurisdiction to change, alter, or amend this Agreement or any term or provision contained therein.

11.12 ~~10.12~~ Counsel.

The Parties may be represented by counsel.

11.13 ~~10.13~~ Evidence.

Evidence submitted in arbitration may be presented in writing or orally. The Parties at a minimum shall disclose all relevant information and documents as would be compellable in a court of law. The Arbitrator may require relevant information and documents to be disclosed by either Party, either prior to or during a hearing, except such documents as would not be compellable if the action were brought in a court of law.

11.14 ~~10.14~~ Arbitration Award.

The Arbitrator shall deliver the award within 90 days following the completion of the hearing.

11.15 ~~10.15~~ Award Final.

The decision of the Arbitrator shall be final and binding on the Parties. The right of any affected Party to appeal an award will be limited to a question of law, provided that leave is first obtained from the Court of Queen's Bench based on the criteria listed in Section 44 of *The Arbitration Act* (Manitoba).

11.16 ~~10.16~~ Costs of Arbitration.

Each Party shall bear its own costs and an equal share of the costs of the Arbitrator, subject to a different award as to costs by the Arbitrator made following the completion of the Arbitration.

11.17 ~~10.17~~ Performance of Obligations.

Each Party agrees to continue performing its obligations under this Agreement while any Dispute is being resolved or arbitrated, subject to any interim order to the contrary issued by the Arbitrator.

11.18 ~~10.18~~ Confidentiality.

All hearings before the Arbitrator shall be closed to the public. All statements and evidence submitted for the arbitration, the decision of the Arbitrator, the fact of the arbitration itself and all other aspects regarding the arbitration shall be kept strictly confidential except as otherwise required by applicable Law or agreed to by the Parties.

11.19 ~~10.19~~ Arbitrator's Undertaking.

Upon appointment, every Arbitrator shall swear or affirm an undertaking in the form set forth in Schedule A.

11.20 ~~10.20~~ Vacancy.

Where a vacancy occurs in the office of the Arbitrator after the commencement of proceedings, the proceedings need not recommence but may, with the unanimous consent of the Parties continue before a replacement Arbitrator. In the absence of such unanimous consent, the arbitration must recommence as if it were a new matter before a new Arbitrator.

11.21 ~~10.21~~ Days.

The word "days" wherever used in this Article ~~X~~XI shall mean calendar days.

ARTICLE XII~~ARTICLE XI~~

GENERAL PROVISIONS

12.1 ~~11.1~~ Notices.

All Notices provided for in this Agreement shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule B hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

12.2 ~~11.2~~ Indemnification.

The Limited Partnership agrees to indemnify and save harmless Hydro and its officers, directors, representatives and employees and agents from any and all claims, demands, proceedings, law suits, damages, liabilities, deficiencies, costs and expenses (including, without limitation all legal fees on a solicitor and client basis) and other professional fees and disbursements, interests, penalties and amounts paid in settlement suffered or incurred by Hydro as a result of or arising directly or indirectly out of or in contravention of any breach by the Limited Partnership of or in any inaccuracy of any representation or warranty of the Limited Partnership contained in this Agreement or in any agreement, certificate or other document delivered pursuant hereto and any breach or non-performance by the Limited Partnership of any covenant to be performed by or pursuant to this Agreement or in any agreement, certificate or other document delivered pursuant hereto.

12.3 ~~11.3~~ Further Assurances.

Each Party ~~hereto,~~ without further consideration, shall promptly do, make, execute or deliver, or cause to be done, made, executed or delivered, all such further acts, documents and things as the other Party ~~hereto~~ may reasonably require from time to time for the purpose of giving effect to this Agreement or more effectively completing any matter provided for in this Agreement and shall take all such steps as may be reasonably within its power to implement to their full extent the provisions of this Agreement.

12.4 ~~11.4~~ Time of the Essence.

Time shall be of the essence of this Agreement.

12.5 ~~11.5~~ Enurement.

This Agreement shall enure to the benefit of and be binding upon the Parties and their permitted assigns.

12.6 ~~11.6~~ Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

12.7 ~~11.7~~ Waivers and Amendments.

Any term, covenant or condition of this Agreement may be amended only with the written consent of the Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed ~~on~~as of the date first above written.

WUSKWATIM POWER LIMITED PARTNERSHIP, by its General Partner 5022649 Manitoba Ltd.

Per:__________________________________
Name: ~~Ken R. F. Adams~~
Title: ~~Chairman~~

THE MANITOBA HYDRO-ELECTRIC BOARD

Per:__________________________________
Name: ~~Robert B. Brennan~~
Title: ~~President and Chief Executive Officer~~

Per:__________________________________
Name: ~~Robert D. Bettner~~
Title: ~~Assistant Corporate Secretary~~

SCHEDULE A

ARBITRATOR'S UNDERTAKING

FORM OF OATH OR UNDERTAKING OF THE ARBITRATOR

I, , do swear and affirm that I will hear the matters referred to me as provided for by the Power Purchase Agreement and The Arbitration Act (Manitoba) in the matter of:

(State particulars of the matter)

and make a true and impartial award, according to the evidence, arguments of the parties, using my skill and knowledge.

DATED this day of , 20 .

Sworn or Affirmed before

A Commission, Notary, etc.

at ______________________

this ___ day of ______, 20__.

SCHEDULE B

NOTICES

Wuskwatim Power Limited Partnership
c/o 5022649 Manitoba Ltd.
~~Attention: Chairman~~
~~3rd Floor, 820 Taylor~~360 Portage Avenue
P.O. 815, Station Main
Winnipeg, MB R3C 2P4
Attention: Chairman

Fax: (204) ~~474-4947~~360-6138

Manitoba Hydro
~~Attention: General Counsel~~
~~3rd Floor, 820 Taylor~~360 Portage Avenue
P.O. 815, Station Main
Winnipeg, MB R3C 2P4
Attention: Ken Tennenhouse, General Counsel

Fax: (204) ~~474-4947~~360-6147

Document comparison by Workshare Compare on May-12-15 12:56:15 PM

Input:	
Document 1 ID	PowerDocs://TDSLAW/325143/29
Description	TDSLAW-#325143-v29-0050406_Power_Purchase_Agreement-draft_#1-090803
Document 2 ID	file://C:/Users/nicolel/AppData/Roaming/OpenText/DM/Temp/TDSLAW-#1805069-v35-Restated_Power_Purchase_Agreement_2014.doc
Description	TDSLAW-#1805069-v35-Restated_Power_Purchase_Agreement_2014
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	580
Deletions	546
Moved from	1
Moved to	1
Style change	0
Format changed	0
Total changes	1128

AMENDED AND RESTATED NCN FINANCING AGREEMENT

between

NISICHAWAYASIHK CREE NATION

– and –

TASKINIGAHP POWER CORPORATION

– and –

THE MANITOBA HYDRO-ELECTRIC BOARD

~~DATED June 28, 2006~~Effective April 1, 2014

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NCN FINANCING AGREEMENT

~~**DATED** the 28th day of June, 2006~~

Effective April 1, 2014

B E T W E E N:

NISICHAWAYASIHK CREE NATION,
(hereinafter referred to as "NCN")

- and –

TASKINIGAHP POWER CORPORATION,
(hereinafter referred to as "TPC")

- and –

THE MANITOBA HYDRO-ELECTRIC BOARD,
(hereinafter referred to as "Hydro")

The parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement, defined terms used herein shall have the following meanings:

~~"**Additional Borrowing Authorizations**" has the meaning specified in Section 4.1(4).~~

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person.

"**Aggregate Capital Contributions**" means for any particular day, the sum of: (i) the subscription price paid for the purchase of the Units by the Limited Partners; and (ii) all other capital amounts contributed by the Limited Partners to the Limited Partnership pursuant to the provisions of the Limited Partnership Agreement.

"**Agreement**" means this financing agreement and all schedules and instruments in amendment or confirmation of it; "**hereof**", "**hereto**" and "**hereunder**" and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; "**Article**", "**Section**" or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement.

"**Anniversary Date**" means each anniversary of the Final Closing Date.

"**Approved Funds**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Auditors**" means such firm of chartered accountants as may be selected by the directors of TPC and approved by NCN from time to time to audit TPC, provided that such firm of chartered accountants is qualified to perform audits in Manitoba.

"**Authorization**" means, with respect to any Person, any authorization, order, permit, approval, grant, licence, consent, right, franchise, privilege, certificate, judgment, writ, injunction, award, determination, direction, decree, by-law, rule or regulation of any Governmental Entity having jurisdiction over such Person, whether or not having the force of Law.

"**Borrowing**" means a borrowing consisting of one or more Dividend Credit Advances.

"**Borrowing Notice**" has the meaning specified in Section 3.2.

"**Business**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Business Day**" means any day on which Hydro's head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba.

"**Canada**" means the Government of Canada.

"**Canadian Dollar Guarantee Rate**" means for any particular day, the closing rate of interest (expressed as a percentage rate per annum) charged on such day by Manitoba to Hydro, as a fee for Manitoba's guarantee of Hydro's Canadian Dollar borrowings.

"**Canadian Dollars**" and "**$**" each mean lawful money of Canada.

"**Canadian Ten Year Rate**" means for any particular day, the rate of interest per annum equal to:

(i) the Ten Year Canada Bond Rate, as at 10:00 a.m. (Winnipeg time), for such day; plus

(ii) the Canadian Dollar Guarantee Rate, as at 10:00 a.m. (Winnipeg time), for such day and either:

(A) plus the Canadian Ten Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread is less than the rate of interest for the Ten Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Ten Year Spread; or

(B) less the Canadian Ten Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread is greater than the rate of interest for the Ten Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Ten Year Spread.

"**Canadian Ten Year Spread**" means at any particular date, the difference between the Ten Year Canada Bond Rate in effect on that date and the rate of interest (expressed as a percentage rate per annum) for Ten Year Manitoba Canadian Dollar Bonds had Ten Year Manitoba Canadian Dollar Bonds been issued by Manitoba on that day at 10:00 a.m. (Winnipeg time) including commission costs, (with the rate of interest determined by Hydro obtaining three rate quotes for Ten Year Manitoba Canadian Dollar Bonds and using the median of the three rate quotes obtained).

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interest in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights, warrants or options to subscribe for or acquire an equity interest in such Person.

"**Change of Control**" means any change which results in NCN no longer directly owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of the bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC, as bare trustee for NCN, commits to vote such Capital Stock in accordance with the direction of Chief and Council of NCN), and for greater certainty the NCN Deed of Assignment does not effect a Change of Control.

"**Chief**" has the meaning ascribed thereto in the PDA.

"Chief and Council" has the meaning ascribed thereto in the PDA.

"**Claim**" means any claim of any nature whatsoever, including any demand, dispute, liability, obligation, debt, action, cause of action, suit, proceeding, litigation, arbitration, judgment, order, award, assessment and reassessment.

"**Collateral**" means TPC's Units and the Distributions thereon in respect of which Hydro has or will have or is intended to have a Lien pursuant to the Security Documents.

"**Corporate Distributions**" means, in respect of any Person, whether or not a corporation, any form of distribution of its profits, including in each case any:

(i) declaration or payment of any dividend on its Capital Stock; and

(ii) payment to purchase, redeem, retire or acquire or reduce the stated capital of any of its Capital Stock, or any option, warrant or other right to acquire any such Capital Stock, or apply or set apart any of its Property therefore.

"**Councillor**" has the meaning ascribed thereto in the PDA.

"**Council Resolution**" has the meaning ascribed thereto in the PDA.

"**Credit Facility Repayment Certification**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Cure Period**" has the meaning specified in Section 8.1(c).

"**Debt**" of any Person means, without duplication:

(i) all obligations of such Person for borrowed money or advances and all obligations of such Person evidenced by bonds, debentures, notes or similar instruments;

(ii) all obligations of such Person, contingent or otherwise, relative to the face amount of all letters of credit, whether or not drawn, and banker's acceptances issued for the account of such Person; and

(iii) all other items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of such Person as of the date at which Debt is to be determined (excluding trade payables incurred in the ordinary course of business).

"**Distributions**" means distributions of cash of the Limited Partnership to TPC and the return of any part of the Aggregate Capital Contributions by the Limited Partnership to TPC.

"**Dividends**" has the meaning ascribed thereto in the NCN Deed of Assignment.

"Dividend Credit Advances" means advances made by Hydro to NCN in Canadian Dollars under this Agreement and "**Dividend Credit Advance**" means any one of such Dividend Credit Advances.

"**Dividend Credit Facility**" means the non-revolving credit facility to be made available to NCN by Hydro in the maximum amount of the Dividend Credit Facility Commitment and in accordance with the terms hereof.

"**Dividend Credit Facility Commitment**" means,

(a) for the calendar year 2015 eighteen million ($18,000,000) dollars, less the sum of NCN Cash Flows From All Sources for the calendar years 2014 and 2015;

(b) ~~"Dividend Credit Facility Commitment" means~~in all other years, the aggregate of the amount calculated on each Anniversary Date prior to, but not including, the Maturity Date derived from the formula "(A x B) – C", where A is the Canadian Ten Year Rate on that Anniversary Date less 2.5%; B is TPC's Own Invested Cash on that Anniversary Date; and C is the aggregate amount of all Distributions from the Limited Partnership on TPC's Dividend Cash Units actually paid out to TPC (and not paid to Hydro pursuant to the irrevocable assignment and direction under the Loan Documents) in the 12-month period ending on such Anniversary Date. (For greater certainty, any Distributions on TPC's Dividend Cash Units which TPC was entitled to receive from the Limited Partnership pursuant to the provisions of the Limited Partnership Agreement but which were paid to Hydro pursuant to the provisions of the Loan Documents or pursuant to the provisions of the TPC Financing Agreement are not, for the purposes of the determination of the Dividend Credit Facility Commitment and any availability thereunder only, included as Distributions on TPC's Dividend Cash Units received by TPC.)

"**Dividend Credit Facility Commitment Cap**" means the amount calculated as at the first Anniversary Date ~~(but after any mandatory payments required by Section 2.6(4) of the TPC Financing Agreement have been made)~~ equal to four times (A) where, (A) is ~~(i)~~ TPC's Own Invested Cash on the first Anniversary Date~~; less (ii) any monies used to repay a Cash Call Credit Advance (as that term is defined in the TPC Financing Agreement); and less (iii) any monies provided to the Limited Partnership pursuant to the Limited Partnership Payment Certification to fund TPC's Operating Cash Call Requirements (as that term is defined in the TPC Financing Agreement). The amounts referred to in (ii) and (iii) hereof will only be required to be deducted from (i) if they would otherwise form part of the amount referred to in (i) hereof~~.

"**Event of Default**" has the meaning specified in Section 8.1.

“**Equity Credit Advances**” has the meaning ascribed thereto in the TPC Financing Agreement.

“**Equity Credit Facility**” has the meaning ascribed thereto in the TPC Financing Agreement.

“**Final Closing**” and “**Final Closing Date**” shall have the respective meanings ascribed thereto in the PDA~~. “**Financial Quarter**” means, in relation to TPC, each successive period of three consecutive months, the first such period beginning on the first day of the first month of TPC’s Financial Year.~~“**Final Investment Closing**” and “**Final Investment Closing Date**” shall have the respective meanings ascribed thereto in the PDA.

“**Financial Year**” means, in relation to TPC, the financial year of TPC determined by the board of directors of TPC.

“**Future Material Agreements**” has the meaning specified in Section 6.1(12).

“**GAAP**” means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the Canadian Institute of Chartered Accountants, or any successor Person at such time.

“**General Partner**” means 5022649 Manitoba Ltd., in its capacity as general partner of the Limited Partnership pursuant to the terms of the Limited Partnership Agreement.

“Government Funds” has the meaning ascribed thereto in the TPC Financing Agreement.

“**Governmental Entity**” means any:

(i) federal, provincial, state, regional, municipal, local or other government, governmental or public department, central bank, court, commission, board, bureau, agency or instrumentality, domestic or foreign;

(ii) any agent, commission, board, or authority of any of the foregoing; or

(iii) any body exercising any regulatory, expropriation or taxing authority under or for the account of any of the foregoing.

"Guarantee" means an unconditional, irrevocable, continuing guarantee executed by TPC in favour of Hydro of the payment and performance by NCN of all of the Obligations on terms and conditions acceptable to Hydro, acting reasonably, and consistent with the terms of this Agreement, which Guarantee shall be delivered by TPC to Hydro at Initial Closing.

"**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the Hydro Act.

"**Hydro Account**" means such account or accounts maintained by Hydro at the Royal Bank of Canada, as Hydro from time to time notifies NCN for the purposes of this Agreement.

"**Hydro Act**" means *The Manitoba Hydro Act*, R.S.M. 1987, c. H190, as amended from time to time.

"**Hydro Liens**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Initial Closing**" and "**Initial Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

"**Initial Limited Partnership Agreement**" means the limited partnership agreement entered into between the General Partner, in its capacity as general partner, and Hydro, as limited partner, dated the 9th day of December, 2004.

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards, or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws.

"**Lien**" means, with respect to any Property, any charge, mortgage, pledge, hypothecation, security interest, lien, conditional sale (or other title retention agreement or lease in the nature thereof), lease, servitude, assignment, adverse claim, defect of title, restriction, trust, or other encumbrance of any kind in respect of such Property, whether or not filed, recorded or otherwise perfected under applicable Laws.

"**Limited Partner**" means one of Hydro or TPC, as the context requires, in its capacity as a limited partner of the Limited Partnership, and "**Limited Partners**" means both of Hydro and TPC, in their respective capacities as limited partners of the Limited Partnership.

"**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement, ~~as amended and restated by~~and continued pursuant to the Limited Partnership Agreement, for the purposes of owning and, directly or indirectly, planning, designing, constructing, operating and maintaining the Wuskwatim Project.

"**Limited Partnership Agreement**" means the ~~limited partnership agreement~~third Amended and Restated Limited Partnership Agreement amending and restating the ~~Initial~~ second Limited Partnership Agreement, dated ~~even date herewith~~April 16, 2015 between the general partner in its capacity as General Partner and Hydro and TPC, in their respective capacities as limited partners.

"**Limited Partnership Payment Certification**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**Loan Documents**" means this Agreement, the Guarantee, the Security Documents, and all other agreements, certificates and instruments delivered or given pursuant to or in connection with the Dividend Credit Facility established under this Agreement; and "**Loan Document**" means any one of such Loan Documents.

"**Loss**" means any loss whatsoever, whether direct or indirect, including expenses, costs, damages, judgments, penalties, fines, charges, claims, demands, liabilities, debts, interest and any and all legal fees and disbursements, on a solicitor and his own client basis.

"**Manitoba**" means the Government of Manitoba.

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in or of itself, but which cumulatively results in a material adverse effect) on:

(i) the ability of NCN or TPC to perform any of their material obligations under the Loan Documents; or

(ii) the ability of Hydro to enforce any of the material obligations of NCN or TPC under the Loan Documents, where Hydro, acting reasonably, has determined that its ability to enforce the said material obligations cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected, notwithstanding that NCN and TPC have provided their written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said material obligations of NCN or TPC under the Loan Documents.

"**Material Agreements**" has the meaning specified in Section 5.1(~~11~~k)(~~c~~iii).

"**Maturity Date**" means the fiftieth Anniversary Date.

"**Member**" means a person who at the relevant time is, or has applied and is entitled to be, a member of NCN pursuant to the membership code established by and for NCN pursuant to Section 10 of the *Indian Act* (Canada), which membership code has been in force and of effect since May 24, 1988 or pursuant to a successor membership code established pursuant to legislation or lawfully adopted by NCN, and "**Members**" means the group of persons each of whom is a Member.

"**NCN**" means the Nisichawayasihk Cree Nation, formerly known as the Nelson House First Nation.

"**NCN Cash Flow From All Sources**" means, for the calendar years 2014 and 2015, the total amount of:

(a) the water rental rebate which NCN received or is entitled to receive from Manitoba for the calendar year pursuant to its water rental rebate agreement with Manitoba;

(b) the interest income on the Hydro Bonds paid or payable to in that calendar year by Hydro in accordance with the One Year Agreement or PDA Supplement No. 2;

(c) three hundred eight thousand twenty-five ($308,025) dollars paid by Hydro to NCN on March 3, 2014 as the remaining NCN Dividend Credit advance for the year 2013; and

(d) the annuity payable by Hydro to NCN for the calendar year pursuant to Article 11 of the PDA Supplement No. 2.

"**NCN Deed of Assignment**" has the meaning ascribed thereto in the PDA.

"**Notice**" means any notice, citation, directive, request for information, writ, summons, statement of claim or other communication from any Person.

"**Obligations**" has the meaning specified in Section 7.1.

"**One Year Agreement**" means the agreement dated November 28, 2013 between NCN and Hydro.

"**Over-Drawn Amount**" has the meaning specified in Section 2.5 (1).

"PDA" means the Project Development Agreement dated June 26, 2006 made between NCN, Hydro, TPC, the General Partner and the Limited Partnership~~.~~ as supplemented and amended by the PDA Supplement No. 1 dated March 15, 2011 and the PDA Supplement No. 2.

"**PDA Supplement No. 2**" means the second supplementary agreement dated April 16, 2015 between NCN, Hydro, Taskinigahp Power Corporation, 5022649 Manitoba Ltd. and Wuskwatim Power Limited Partnership.

"**Permitted Liens**" means, with respect to any Person, any one or more the following:

(i) Liens for Taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such taxes, assessments and charges;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(ii) Liens resulting from any judgment rendered or Claim filed against such Person which such Person shall be contesting in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such judgment or Claim;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(iii) undetermined Liens arising in the ordinary course of business which have not at such time been filed pursuant to Law against such Person or which relate to obligations not due or delinquent;

(iv) Liens arising in the ordinary course of business which are not registered against title to the Collateral and are not overdue for a period of more than thirty (30) days or which are being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion, (i) adequate security has been provided to ensure payment of such Liens; (ii) adequate reserves with respect thereto are maintained on the consolidated books of such Person in accordance with GAAP; and (iii) in each case, such Liens will not materially interfere with use of such Property by the Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(v) any Lien, payment of which has been provided for by the depositing with Hydro of an amount in cash, or the obtaining of a surety bond satisfactory to Hydro, in its absolute discretion, sufficient in either case to pay or discharge such Lien and which deposit or bond Hydro is authorized to use or draw upon for that purpose;

(vi) Liens securing Purchase Money Debt; provided that: (i) such Liens shall extend only to the specific Property of TPC acquired with the proceeds of such Purchase Money Debt (and not any other portion of the Collateral); and (ii) recourse in respect of such Liens shall be limited to such specific Property;

(vii) the Hydro Liens; or

(viii) any other Lien approved in writing in advance by Hydro in its unfettered discretion.

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture, band within the meaning of the *Indian Act* (Canada) or other entity or Governmental Entity, and pronouns have a similarly extended meaning.

"**Property**" means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including capital stock in any other Person.

“**Purchase Money Debt**” means, with respect to any Person, all obligations of such Person incurred to finance the acquisition of Property.

“**Receiver**” means a receiver, receiver and manager or other Person having similar powers or authority appointed by Hydro or by a court at the instance of Hydro in respect of the Collateral or any part thereof.

“**Repayment Notice**” has the meaning specified in Section 2.6(1).

“**Reserve**” shall have the meaning ascribed thereto in the *Indian Act* (Canada).

“Revenue Advance Consolidation Agreement” has the meaning ascribed thereto in the PDA.

“**Sale**” has the meaning ascribed thereto in the TPC Financing Agreement.

“**Security Documents**” means those agreements and other documents in favour of Hydro described in Schedule G in form and substance satisfactory to Hydro, acting reasonably, as such documents may be amended or restated from time to time, as security for all or any portion of the Obligations.

“**Subsidiary**” means, at any time, as to any Person, any corporation or other Person, if at such time the first-mentioned Person owns, directly or indirectly, securities or other ownership interests in such corporation or other Person, having ordinary voting power sufficient to elect a majority of the board of directors or persons performing similar functions for such corporation or other Person or has the power to determine the policies and conduct of the management of such corporation or other Person and for greater certainty includes a Subsidiary of a Subsidiary.

"TPC" means Taskinigahp Power Corporation, a corporation that is wholly owned by NCN beneficially, and by the Chief or a Councillor of NCN as registered owner and bare trustee for NCN.

"**TPC Financing Agreement**" means ~~a financing agreement dated even date herewith~~the Amended and Restated TPC Financing Agreement dated April 16, 2015 between TPC and Hydro.

"**TPC's Cash Units**" has the meaning ascribed thereto in the TPC Financing Agreement.

"TPC's Dividend Cash Units" means:

(i) on the Final ~~Closing Date, (but after any mandatory payments required by Section 2.6(3) of the TPC Financing Agreement have been made and after any sale of TPC's Units pursuant to Article V or Article VI of the TPC Financing Agreement has closed in accordance with Article VII of the TPC Financing Agreement)~~Investment Date, that the number of TPC's Units equal to (A) divided by (B) where (A) equals the number of TPC's Units on the Final ~~Closing~~Investment Date multiplied by TPC's Own Invested Cash as of that date; and (B) equals the sum of: (i) the aggregate amount of Equity Credit Advances which remain outstanding on that date; and (ii) TPC's Invested Cash as of that date;

(ii) on any particular day after the Final ~~Closing~~Investment Date (the "**Measurement Date**") until the date that the Equity Credit Facility (as defined in the TPC Financing Agreement) has been paid out in full, that number of TPC's Units equal to (A) divided by (B) where (A) is a product of: (i) the number of TPC's Dividend Cash Units on the Final ~~Closing~~Investment Date; multiplied by (ii) the number of TPC's Units on the Measurement Date; and (B) equals the number of TPC's Units on the Final ~~Closing~~Investment Date; and

(iii) on the date when the Equity Credit Facility has been paid out in full, all of TPC's Units shall be deemed to be TPC's Dividend Cash Units.

"**TPC's Invested Cash**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**TPC's Own Funds**" has the meaning ascribed thereto in the TPC Financing Agreement.

"**TPC's Own Invested Cash**" means on any day, the amount of TPC's Invested Cash on that day, excluding any portion which is not TPC's Own Funds.

"**TPC's Units**" means, at any time, all of the Units owned by TPC.

"**Taskinigahp Trust**" has the meaning ascribed thereto in the PDA.

"**Taxes**" means all taxes imposed by any Governmental Entity, including, real property, personal property, goods and services, sales, transfer, purchase, stumpage, registration, capital, excise, import duties, payroll, unemployment, disability, employee's income withholding, social security or withholding.

"**Ten Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of ten years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian dollar non callable Government of Canada reference bonds with a ten year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the ten year term, and using the median rate of the three rate quotes obtained).

"**Ten Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba at 100% of the principal amount for a term of ten years.

~~"**Time of Final Closing**" means 10:00 o'clock in the forenoon, Winnipeg time, on the Final Closing Date.~~

"**Total Outstandings**" means, at any time, with respect to the Dividend Credit Facility, the aggregate amount in Canadian Dollars of all outstanding Dividend Credit Advances.

"**Unit**" means one of the units in the Limited Partnership issued to and subscribed for by a Limited Partner pursuant to the Limited Partnership Agreement, and "**Units**" means all of the issued Units in the Limited Partnership.

"Wuskwatim Project" has the meaning ascribed thereto in the PDA.

1.2 Interpretation.

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, any other Loan Document or any provisions hereof or thereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word “including” shall mean “including without limitation” and “includes” shall mean “includes without limitation”;

(e) the expressions “the aggregate”, “the total”, “the sum” and expressions of similar meaning shall mean “the aggregate (or total or sum) without duplication”;

(f) in the computation of periods of time, unless otherwise expressly provided, the word “from” means “from and including” and the words “to” and “until” mean “to but excluding”;

(g) accounting terms not specifically defined shall be construed in accordance with GAAP. Except as otherwise mandated by changes in GAAP from time to time, the financial statements required to be delivered pursuant to this Agreement shall be prepared, and all calculations made for the purposes of this Agreement shall be made, unless otherwise provided for herein, by the application of GAAP applied on a basis consistent with the most recent audited financial statements of TPC, previously delivered to Hydro; and

(h) for the purposes of this Agreement, a Person (the “**first Person**”) shall be deemed to be “**Controlled**” by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

(i) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

(ii) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person,

and “**Controlled**” and “**Controlling**” shall have the corresponding meaning.

1.3 <u>Interpretation of other Loan Documents.</u>

The provisions of Article 1.2 shall apply to the interpretation of all of the other Loan Documents unless specifically otherwise indicated therein.

1.4 <u>Severability.</u>

If any provision of this Agreement or any other Loan Document is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement or such Loan Documents and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions hereof or thereof shall be unaffected by such provision and shall continue to be valid and enforceable.

1.5 <u>Entire Agreement.</u>

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the parties relating to the subject matter hereof and entered into prior to the date of this Agreement.

1.6 <u>Waiver.</u>

No failure on the part of Hydro to exercise, and no delay in exercising, any right under this Agreement or any other Loan Document shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement or any other Loan Document preclude any other or further exercise thereof or the exercise of any other right, nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No notice to or demand on NCN or TPC (as applicable) in any case shall entitle it to any notice or demand in similar or other circumstances, unless such notice or demand is required under the terms of this Agreement or the applicable Loan Document. No waiver of any of the provision of this Agreement or any other Loan Document shall be effective unless it is in writing duly executed by the waiving party.

1.7 Governing Law.

This Agreement and each other Loan Document, shall be governed by, and interpreted in accordance with, the Laws of Manitoba and the Laws of Canada applicable therein.

1.8 Incorporation of Schedules.

The following schedules attached shall, for all purposes hereof, be incorporated in and form an integral part of this Agreement:

Schedule A	Repayment Notice
Schedule B	Borrowing Notice
Schedule C	Material Agreements
Schedule D	Issued and Outstanding Capital Stock and Debt
Schedule E	Liabilities
Schedule F	Address for Notice
Schedule G	List of Security Documents
Schedule H	Authorizations

It is acknowledged by Hydro that Schedules C to E (both inclusive) ~~shall be~~were delivered by NCN to Hydro on or before the Initial Closing Date for attachment ~~hereto, and upon the delivery and attachment, the said~~to the Initial NCN Financing Agreement, which Schedules shall be deemed to form part of this Agreement.

1.9 Conflicts.

If a conflict or inconsistency exists between a provision of this Agreement and a provision of any of the other Loan Documents or any part thereof, then the provisions of this Agreement shall prevail. Notwithstanding the foregoing, if there is any right or remedy of Hydro set out in any of the other Loan Documents or any part thereof which is not set out or provided for in this Agreement, such additional right or remedy shall not constitute a conflict or inconsistency.

ARTICLE II
DIVIDEND CREDIT FACILITY

2.1 Dividend Credit Facility.

Hydro agrees, on the terms and conditions of this Agreement, to make available to NCN the Dividend Credit Facility by making such Dividend Credit Advances to NCN as may be requested by NCN hereunder at any time and from time to time in accordance with this Agreement.

2.2 Commitment and Dividend Credit Facility Limit.

(1) Hydro shall not be obliged to make any Dividend Credit Advance or Dividend Credit Advances which would cause the Total Outstandings to be greater than the Dividend Credit Facility Commitment, and commencing on the day after the twenty-fifth Anniversary Date, Hydro shall in addition not be obliged to make any Dividend Credit Advance or Dividend Credit Advances which would cause the Total Outstandings, including accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility, to be greater than the Dividend Credit Facility Commitment Cap, provided that where each of NCN and TPC is otherwise in good standing under the Loan Documents, Hydro shall advance in accordance with the provisions of this Agreement, as a Dividend Credit Advance to NCN, upon request, the lesser of: (i) the amount requested by NCN; (ii) the amount hereunder which would, when advanced, cause the Total Outstandings to equal, but not exceed, the Dividend Credit Facility Commitment; and (iii) if the Advance is requested after the twenty-fifth Anniversary Date, the amount hereunder which would, when advanced, cause the Total Outstandings, including accrued and unpaid interest and all other amounts owing under the Dividend Credit Facility, to equal, but not exceed, the Dividend Credit Facility Commitment Cap.

(2) The Dividend Credit Facility may be utilized by NCN commencing as of the first Anniversary Date subject to the terms and conditions of this Agreement. The Dividend Credit Advance, if any, available at the end of each Anniversary Date, in accordance with the provisions of this Agreement, must be requested within ~~a time period not greater than 220 days after the applicable Anniversary Date but not less than 130 days after the applicable Anniversary Date~~the time period between November 1 and February 1 in any year.

(3) The Dividend Credit Facility is a non-revolving credit and the principal amount of any Dividend Credit Advance that is repaid may not be re-borrowed and shall be a permanent reduction of the Dividend Credit Facility Commitment.

(4) Any available amount under the Dividend Credit Facility that NCN does not request a Dividend Credit Advance for by the date set out in Section 2.2(2) shall be a permanent reduction of the Dividend Credit Facility Commitment.

2.3 Available Dividend Credit Advances.

(1) Hydro shall, on the terms and conditions of this Agreement, make the Dividend Credit Advances available to NCN under the Dividend Credit Facility in accordance with Section 3.2.

(2) All Dividend Credit Advances requested hereunder shall be made available to NCN in accordance with Article III.

2.4 Repayment on the Maturity Date.

The Total Outstandings, if any, and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility shall become due and payable on the Maturity Date and subject to Hydro making an early demand for payment pursuant to Section 8.1 following an Event of Default, NCN shall repay on the Maturity Date, the Total

Outstandings, if any, all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility. Notwithstanding the foregoing, if on the Maturity Date, NCN and TPC are not in default in respect of any material provision of the Loan Documents, the amount of the Total Outstandings and all accrued and unpaid interest thereon on the Maturity Date and all other amounts owing to Hydro under the Dividend Credit Facility will, subject to the right to prepay in accordance with the provisions of this Agreement, be repaid to Hydro solely through Hydro receiving all Distributions from time to time on TPC's Units. The Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility; second, in payment of all accrued and unpaid interest under the Dividend Credit Facility; and third, in repayment of all principal amounts under the Dividend Credit Facility. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro, as provided for under the Security Documents, until the Total Outstandings and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility have been repaid in full out of the said Distributions; provided however, that the payments to be made to Hydro pursuant to this Section 2.4 out of the Distributions on TPC's Units, shall be paid in the order of priority as set out in Section 3.7 of the TPC Financing Agreement, and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement or the Revenue Advance Consolidation Agreement, the non-payment of such Distributions to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

It is acknowledged that Hydro shall have no right to sue NCN on the personal covenant to pay the said amounts, nor to sue TPC on any personal covenant to pay the said amounts under the Guarantee; it being acknowledged that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Security Documents.

2.5 Mandatory Repayments during the Term of this Agreement.

(1) If, on any day, Hydro notifies NCN that the Total Outstandings exceeds the Dividend Credit Facility Commitment, (and commencing on the day after the twenty-fifth Anniversary Date, the Total Outstandings exceeds the lesser of the Dividend Credit Facility Commitment or the Dividend Credit Facility Commitment Cap) (such excess being referred to herein as the "**Over-Drawn Amount**"), NCN shall repay to Hydro, an amount sufficient to reduce the Total Outstandings by at least the Over-Drawn Amount. Notwithstanding the foregoing, provided that NCN and TPC are not in default in respect of any material provision of the Loan Documents, and subject always to the right to prepay as set out herein, the Over-Drawn Amount and all accrued and unpaid interest thereon and applicable costs and expenses, if any, will be repaid solely through the Distributions from time to time on TPC's Units pursuant to the provisions of the Security Documents. The Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility; second, in payment of all accrued and unpaid interest under the Dividend Credit Facility; and third, in repayment of all principal amounts under the Dividend Credit Facility. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for in the Security Documents until the Over-Drawn Amount and all costs and expenses and accrued and unpaid interest thereon has been repaid in full. The payments made to Hydro pursuant to this Section 2.5(1) out of the Distributions on TPC's Units shall be paid in the order of priority as set out in Section 3.7 of the TPC Financing Agreement and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement in compliance with such priority provisions, the non-payment of such Distributions

to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

(2) In addition to all other mandatory repayment obligations provided for in this Agreement and subject always to the right to prepay in accordance with the provisions of this Agreement, NCN shall throughout the term of this Agreement repay to Hydro the Total Outstandings plus all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Dividend Credit Facility solely through Hydro receiving all Distributions on TPC's Units. Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above); second, in payment of all accrued and unpaid interest under the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above); and third, in repayment of all principal amounts under the Dividend Credit Facility (except to the extent that they are dealt with under subsection (1) above). Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until all such amounts have been repaid in full. The amount of any repayment shall be a permanent reduction of the Dividend Credit Facility Commitment. The payments to be made to Hydro pursuant to this Section 2.5(2) out of Distributions on TPC's Units shall be paid in the order of priority as set out in Section 3.7 of the TPC Financing Agreement and for so long as Distributions are paid to Hydro pursuant to the TPC Financing Agreement or the Revenue Advance Consolidation Agreement in compliance with such priority provisions, the non-payment of such Distributions to Hydro pursuant to the provisions of this Agreement shall not be deemed to be a default by TPC under this Agreement.

(3) It is acknowledged that Hydro shall have no right to sue NCN on the personal covenant to pay the said amounts, nor to sue TPC on any personal covenant to pay the said amounts under the Guarantee, it being acknowledged that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Security Documents.

2.6 <u>Optional Reductions.</u>

(1) Subject to Section 2.6(2), NCN may prepay, in whole or in part, the Total Outstandings, at any time, upon at least two (2) Business Days notice to Hydro (the "**Repayment Notice**"). Each Repayment Notice shall be in substantially the form of Schedule "A" and shall specify:

(a) the proposed date of such prepayment or reduction; and

(b) the aggregate principal amount of the prepayment or reduction, and, if such Repayment Notice is given, NCN shall:

(c) pay Hydro in accordance with such Repayment Notice the amount of prepayment; and

(d) pay Hydro all interest on the amount of such prepayment or excess amount accrued to the date of such prepayment.

(2) Each partial prepayment of Total Outstandings shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.

2.7 <u>Evidence of Debt and Determination of Interest Rates and Fees.</u>

(1) The indebtedness of NCN in respect of all Dividend Credit Advances hereunder shall be evidenced by the account records maintained by Hydro, which shall be *prima facie* evidence of such indebtedness for all purposes, absent error. Hydro

shall indemnify and save harmless NCN for losses suffered or costs incurred by NCN due to Hydro's failure to correctly record or calculate any amount, rate, date or other data (including calculations by Hydro to determine any amount) in the account records or in statements or notices issued to NCN, where such failure was due to the gross negligence or willful misconduct of Hydro or any person for whom Hydro is responsible at law. Notwithstanding the foregoing, the failure of Hydro to correctly record or calculate any amount, rate, date or other data (including calculations to determine any amount) in the account records, or in statements or notices issued to the Limited Partnership hereunder shall not affect the obligation of NCN and TPC to pay amounts due hereunder to Hydro in the manner contemplated herein, and in accordance with the other Loan Documents.

(2) For purposes of the *Interest Act* (Canada):

(a) whenever any interest under this Agreement is calculated using a rate based on a period of time other than a calendar year, such rate determined pursuant to such calculation, when expressed as an annual rate, is equivalent to (x) the applicable rate based on such period of time multiplied by (y) the actual number of days in the calendar year in which the period for which such interest or fee is calculated ends, and divided by (z) the number of days in such period of time;

(b) the principle of deemed reinvestment of interest shall not apply to any interest calculation under this Agreement; and

(c) the rates of interest stipulated in this Agreement are intended to be nominal rates and not effective rates or yields.

(3) Within ten (10) Business Days of the last day of each month during this Agreement Hydro shall provide to NCN a written statement setting out the following information as at the last day of each month:

(a) the Total Outstandings under the Dividend Credit Facility, together with the following information:

(i) opening balances;

(ii) closing balances;

(iii) Dividend Credit Advances provided during the month;

(iv) principal repaid during the month, if applicable;

(v) interest paid by or on behalf of NCN, and applicable interest rate(s) charged to NCN during the month; and

(vi) any costs charged by Hydro to NCN during the month, and any reimbursements made by or on behalf of NCN to Hydro during the month for costs charged by Hydro to NCN.

ARTICLE III
DIVIDEND CREDIT ADVANCES

3.1 <u>Dividend Credit Advances.</u>

Hydro agrees, on the terms and conditions of this Agreement, to make Dividend Credit Advances to NCN under the Dividend Credit Facility, from time to time, on any Business Day.

3.2 <u>Procedure for Borrowing.</u>

Where NCN wishes to receive a Dividend Credit Advance under the Dividend Credit Facility, a notice (a "**Borrowing Notice**") shall be given by NCN to Hydro not later than 10:00 a.m. (Winnipeg time), at least two (2) Business Days but not more than five (5) Business Days prior to the date of the proposed Dividend Credit Advance, which Borrowing Notice shall be irrevocable and binding on NCN. Each Borrowing Notice shall be in substantially the form of Schedule B and shall specify:

(a) the requested date of the Dividend Credit Advance; and

(b) the aggregate amount of the Dividend Credit Advance.

Subject to the terms and conditions of this Agreement, Hydro shall forward the funds for the Dividend Credit Advance on the specified date for such Dividend Credit Advance in accordance with the Borrowing Notice forwarded to Hydro.

3.3 Interest on Dividend Credit Advances.

Each Dividend Credit Advance, or the amount thereof remaining outstanding ~~form~~ from time to time, shall bear interest at the rate applicable to the Dividend Credit Advance determined in accordance with this Section 3.3 from the date ~~such~~ the Dividend Credit Advance is first received in the account specified by NCN in the applicable Borrowing Notice to the date on which ~~such~~ the Dividend Credit Advance is repaid in full or dealt with as otherwise specified in this Agreement. Each Dividend Credit Advance shall bear interest at a rate per annum equal at all times for that Dividend Credit Advance to the Canadian Ten Year Rate in effect on the date the said Dividend Credit Advance is first received in the account specified by NCN in the applicable Borrowing Notice~~, plus three (3%) percent per annum~~. Interest on each of the Dividend Credit Advances made March 3, 2014, January 5, 2015 and on any date prior to November 1, 2015 shall be calculated monthly and compounded semi-annually from the date of advance to October 31, 2015. After November 1, 2015, if a Dividend Credit Advance is received in the account specified by NCN on a date other than November 1 of the year, interest on that Dividend Credit Advance shall accrue in the current month and be added to the Total Outstandings. Commencing November 1, 2015 and in each month thereafter Hydro shall calculate a blended interest rate based on the interest rates applicable to each Dividend Credit Advance, in proportion to the amount of each Dividend Credit Advance and the accrued interest thereon to that date, which rate shall be applied to all Dividend Credit Advances and all other amounts owing to Hydro under the Dividend Credit Facility on that date to October 31 of the following year. If there is no Dividend Credit Advance during a month, the blended rate for the month shall continue to apply. Such interest shall be calculated and compounded semi-annually and shall only become due and payable on the Maturity Date subject to the provisions of this Agreement (including payments made through Distributions under Article II~~ and subject to~~, NCN's optional right of prepayment ~~hereunder and except as otherwise stipulated in this Agreement~~ and action taken if an Event of Default occurs). Hydro shall provide NCN with notice of the Canadian Ten Year Rate applicable to each such Dividend Credit Advance and notice of the blended interest rate, together with its supporting calculation of the Canadian Ten Year Rate and the blended interest rate which will constitute, in the absence of error, *prima facie* evidence of the Canadian Ten Year Rate and the blended interest rate applicable to each such Dividend Credit Advance and all other amounts owing to Hydro under the Dividend Credit Facility.

3.4 TPC Financing Agreement.

Notwithstanding any other provision of this Agreement, it is acknowledged and agreed by the parties hereto that in the event that TPC sells all of TPC's Units to Hydro, whether pursuant to any Sale (as that term is defined in the TPC Financing Agreement), or otherwise, the Total Outstandings under the Dividend Credit Facility, all costs hereunder and all other amounts whatsoever owed by NCN to Hydro under this Agreement or any Loan Documents pursuant hereto (including the Guarantee) shall be deemed to have been paid in full and satisfied by the sale of TPC's Units to Hydro. NCN's right to receive Dividend Credit Advances will be suspended when Hydro receives notice that TPC is exercising its right to sell all of TPC's Units pursuant to the provisions of the TPC Financing Agreement or upon Hydro providing notice to TPC that it is exercising its right to purchase all of TPC's Units pursuant to the provisions of the TPC Financing Agreement. The Dividend Credit Facility will terminate on the date that the sale of TPC's Units is completed in accordance with the provisions of the TPC Financing Agreement.

ARTICLE IV
CONDITIONS OF LENDING

~~**4.1 Conditions Precedent to Initial Dividend Credit Advance.**~~

~~The obligation of Hydro to make Dividend Credit Advances under the Dividend Credit Facility commencing as of the first Anniversary Date is subject to the following conditions to be fulfilled or performed at or prior to Initial Closing Date, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro:~~

~~(1) **Deliveries**. Hydro shall have received, at or prior to the Initial Closing Date, the following, each dated such day as is satisfactory to Hydro:~~

~~(a) certified copies of:~~

~~(i) Council Resolution of NCN approving the entering into of this Agreement and the other Loan Documents to which it is a party and the completion of all transactions contemplated hereunder and thereunder;~~

~~(ii) the constating documents and by-laws of TPC; and~~

~~(iii) resolutions of the board of directors of TPC approving the entering into this Agreement and the other Loan Documents to which it is a party and the completion of all transactions contemplated hereunder and thereunder;~~

~~(b) certificate of the Chief of NCN setting forth the name and title of the Chief of NCN and each Councillor of NCN and certifying the names and true signatures of the persons authorized to sign this Agreement and the other Loan Documents to which NCN is a party on behalf of NCN;~~

~~(c) certificate of an officer of TPC certifying the names and true signatures of the persons authorized to sign this Agreement and the other Loan Documents to which TPC is a party on behalf of TPC;~~

~~(d) certificate of status with respect to TPC;~~

~~(e) the Guarantee, in form and substance satisfactory to Hydro, acting reasonably, duly executed and delivered by TPC;~~

~~(f) the Security Documents creating a first charge security interest in TPC's Units and the Distributions on TPC's Units and all rights related to TPC's Units and the said Distributions, in form and substance satisfactory to Hydro, acting reasonably;~~

~~(g) original certificate(s) for TPC's Units, together with duly executed power of attorney in respect of TPC's Units (to be held by Hydro pursuant to the terms of the Security Documents), together with an irrevocable direction from TPC, directing and authorizing the General Partner that all certificates for any TPC's Units issued subsequent to Initial Closing, shall not be forwarded to TPC but shall immediately be forwarded directly to Hydro (to be held by Hydro pursuant to the terms of the Security Documents). All original certificates shall be returned to TPC after the Dividend Credit Facilities under this Agreement have been terminated and the Credit Facilities (as that term is defined in the TPC Financing Agreement) have been terminated and there are no outstanding Obligations under this Agreement or under the TPC Financing Agreement (as defined in that Agreement);~~

~~(h) evidence of the registration of the Security Documents in all offices where such registration, filing or recording is necessary or desirable to protect any rights or remedies of Hydro thereunder and receipt of legal opinions of registration counsel in form and substance acceptable to Hydro, provided however that Hydro shall~~

~~use its commercially reasonable efforts to complete all such registrations and to obtain the required evidence and opinions from its legal counsel in advance of the Initial Closing Date;~~

~~(i) legal opinions of counsel to NCN confirming the due authorization, execution, and delivery of this Agreement and the other Loan Documents to which NCN is a party only, subject to customary qualifications and assumptions for such opinions given in respect of a First Nation (but, for greater certainty, no opinions as to enforceability will be required from legal counsel to NCN);~~

~~(j) legal opinions of counsel to TPC confirming the due authorization, execution and delivery of this Agreement and the other Loan Documents to which TPC is a party only, subject to customary qualifications and assumptions for such opinions (but, for greater certainty, no opinions as to enforceability will be required from legal counsel to TPC);~~

~~(k) a copy of each Material Agreement, which shall be in form and substance acceptable to Hydro, in its discretion acting reasonably;~~

~~(l) duly completed Schedules C, D and E to this Agreement in form and substance satisfactory to Hydro, acting reasonably; and~~

~~(m) such other certificates and documentation as Hydro may reasonably request to give effect to this Agreement.~~

~~(2) **No Material Adverse Business Effect**. No event, condition or circumstance has arisen which would have a Material Adverse Business Effect.~~

~~(3) **Due Diligence.** Hydro shall have completed its due diligence in respect of NCN, TPC and the Material Agreements and shall be satisfied with the results of such due diligence, in its sole discretion.~~

~~(4) **Authorizations.** Hydro has received all Authorizations that it requires for the due performance of the Loan Documents (which Authorizations are specified in Schedule H) with the sole exception that Hydro will require additional borrowing authority from Manitoba under applicable legislation for amounts to be borrowed by Hydro after August 31, 2006, to fund Advances requisitioned by NCN by Borrowing Notices thereafter (the "**Additional Borrowing Authorizations**"). Hydro covenants and agrees to use its best efforts to obtain such Additional Borrowing Authorizations as may be required by it from time to time for the due and timely performance of its covenants under the Loan Documents.~~

~~(5) **PDA**. All of the conditions set forth in Article XIII of the PDA have been fulfilled or performed.~~

~~(6) **Other Conditions**. The conditions set forth in Section 4.2 shall have been fulfilled or performed.~~

~~**4.2 Additional Conditions Precedent to Initial Dividend Credit Advance.**~~

~~The obligation of Hydro to make Dividend Credit Advances under the Dividend Credit Facility commencing on the first Anniversary Date is subject to the following conditions to be fulfilled or performed at or prior to the Final Closing Date, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro:~~

~~(1) **PDA.** All of NCN's and TPC's obligations to be performed or fulfilled on or before the Final Closing Date pursuant to the provisions of the PDA have been fulfilled or performed and NCN and TPC are in compliance with all of the provisions of the PDA.~~

~~(2) **TPC Financing Agreement.** All of TPC's obligations to be performed or fulfilled on or before the Final Closing Date pursuant to the provisions of the TPC~~

~~Financing Agreement have been fulfilled or performed and TPC is in compliance with all provisions of the TPC Financing Agreement.~~

~~(3) **Limited Partnership.** TPC is a limited partner of the Limited Partnership.~~

4.1 ~~4.3~~ Conditions of All Dividend Credit Advances.

At any time, the obligation of Hydro to make a Dividend Credit Advance shall be subject to the following conditions being satisfied on the date of such Dividend Credit Advance, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro, in its sole discretion:

~~(1)~~ (a) **Facility Limits**. The Total Outstandings shall not:

~~(a)~~ (i) prior to or after giving effect to the Dividend Credit Advance, exceed the Dividend Credit Facility Commitment; provided however that where a Dividend Credit Advance requested by NCN would cause the Total Outstandings to exceed the Dividend Credit Facility Commitment, Hydro shall make a Dividend Credit Advance equal to the amount that shall cause the Total Outstandings to equal, but not exceed, the Dividend Credit Facility Commitment; and

~~(b)~~ (ii) commencing on the day after the twenty-fifth Anniversary Date, the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility shall not, after giving effect to the Dividend Credit Facility Advance, exceed the Dividend Credit Facility Commitment Cap; provided however, that where a Dividend Credit Advance requested by NCN would cause the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility to exceed the Dividend Credit Facility Commitment Cap, Hydro shall make a Dividend Credit Advance equal to the amount that shall cause the Total Outstandings and all accrued and unpaid interest, costs and expenses and all other amounts owing under the Dividend Credit Facility, to equal, but not exceed, the Dividend Credit Facility Commitment Cap.

~~(2)~~ (b) **Truth of Representations and Warranties**. The representations and warranties of NCN and TPC contained in this Agreement and in any other Loan Documents to which each is a party, shall be true and correct as of the date on which any Dividend Credit Advance is made with the same force and effect as if such representations and warranties had been made on and as of such date; provided that, to the extent the disclosure in the representations and warranties is no longer true and correct, NCN and TPC shall be entitled to update such disclosure to Hydro, and if such disclosure is not materially adverse it must be approved by Hydro.

~~(3)~~ (c) **Performance of Covenants**. NCN and TPC shall have fulfilled or complied with all covenants herein contained (or contained in any other Loan Documents to which each is a party) to be performed by it at or prior to the date of such Dividend Credit Advance.

~~(4)~~ (d) **No Event of Default**. No Event of Default shall have occurred and be continuing.

~~(5)~~ (e) **Authorizations**. Hydro has obtained such borrowing authority (including the Additional Borrowing Authorizations) as may be required by it from time to time for the due and timely performance of its covenants under the Loan Documents, including in order to enable it to make the Advances requisitioned from time to time by NCN by Borrowing Notices.

~~(6)~~ (f) **No Change in Laws**. No Law or change in any Law shall have been enacted, the effect of which will be to prohibit Hydro from making any Dividend Credit Advance.

~~(7)~~ (g) **Borrowing Notice**. Hydro shall have received a Borrowing Notice in compliance with this Agreement.

ARTICLE V

REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties.

To induce Hydro to make Dividend Credit Advances available hereunder, NCN and TPC represent and warrant to Hydro that each of the following representations and warranties is true and correct:

~~(1)~~ **(a) Status and Power.**

~~(a)~~ (i) NCN is a "band" within the meaning of the Indian Act (Canada) and has the power to own or lease its personal property and its real property, other than the Reserve;

~~(b)~~ (ii) TPC is a corporation duly incorporated and organized and validly subsisting under the laws of Manitoba and has full corporate power and capacity to own its property and carry on its Business. TPC is duly qualified, licenced or registered to carry on business in Manitoba.

~~(2)~~ **(b) Authorization.**

~~(a)~~ (i) NCN has full power and capacity and full legal right to enter into and perform its obligation under this Agreement and the other Loan Documents to which it is or will be a party and has, or will have by the Initial Closing Date, taken all action necessary to be taken by it to authorize such acts;

~~(b)~~ (ii) TPC has full power and capacity and full legal right to enter into and perform its obligations under this Agreement and the other Loan Documents to which it is or will be a party and has or will have by the Initial Closing Date taken all action necessary to be taken by it to authorize such acts.

~~(3)~~ **(c) Enforceability of Agreement.**

~~(a)~~ (i) This Agreement and each other Loan Document to which NCN is a party constitutes legal, valid and binding obligations of NCN enforceable against it in accordance with their respective terms except as enforcement may be limited by the provisions of the Indian Act (Canada) and subject only to any limitation under applicable Laws relating to~~:~~ bankruptcy, insolvency, reorganization, moratorium or creditor's rights generally and the discretion that a court may exercise in the granting of equitable remedies;

~~(i) bankruptcy, insolvency, reorganization, moratorium or creditors' rights generally; and~~

~~(ii) the discretion that a court may exercise in the granting of equitable remedies;~~

~~(b)~~ (ii) this Agreement and each other Loan Document to which TPC is a party constitutes legal, valid and binding obligations of TPC enforceable against it in accordance with their respective terms, subject only to any limitation or applicable laws relating to~~:~~ bankruptcy, insolvency, reorganization, moratorium or creditor's rights generally and the discretion that a court may exercise in the granting of equitable remedies;

~~(i) bankruptcy, insolvency, reorganization, moratorium or creditors' rights generally; and~~

~~(ii) the discretion that a court may exercise in the granting of equitable remedies.~~

~~(4)~~ **(d) Government Approval and Regulation.** No authorization or approval or other action by, and no notice to or filing with, any Governmental Entity or other Person (other than those that have been, or by the Initial Closing Date will be, duly obtained or made) is required for the due execution, delivery or performance by NCN or TPC of any Loan Document to which NCN or TPC is a party.

~~(5)~~ **(e) Litigation.** There is no material action, suit or proceeding which has been commenced (Notice of which has been served on NCN or TPC), or to the best of the knowledge of NCN or TPC, is pending or threatened against NCN or TPC before or by any Governmental Entity, or before any arbitrator or board, which would prevent NCN or TPC from performing its obligations under any of the Loan Documents to which it is a party. NCN and TPC are not in default with respect to any judgment, order, writ, injunction, decree or award of any court, arbitrator, board or other Governmental Entity, nor is there any judgment, order, writ, injunction, decree or award which would prevent NCN or TPC from performing its obligations under any of the Loan Documents to which either is a party.

~~(6)~~ **(f) Imposition of Lien.** The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents to which it is a party by NCN will not result in or require the creation or imposition of any Lien on any Property of NCN except as otherwise permitted by this Agreement or the Loan Documents. The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents to which it is a party by TPC will not result in or require the creation or imposition of any Lien on the Property of TPC except as otherwise permitted by this Agreement or the Loan Documents.

~~(7)~~ **(g) No Other Material Facts.** None of:

~~(a)~~ (i) this Agreement;

~~(b)~~ (ii) any of the other Loan Documents; or

~~(c)~~ (iii) any certificate or statement in writing which has been supplied by or on behalf of NCN or TPC and is a document that is required to be delivered to Hydro pursuant to the provisions of this Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

~~(8)~~ **(h) Restrictive Documents.**

~~(a)~~ (i) NCN is not subject to, nor a party to any by-laws or resolutions of Chief and Council or of Members (or of any committees thereof, respectively), of NCN any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement and each of the other Loan Documents to which it is a party or compliance by NCN with the terms, conditions and provisions hereof or thereof;

~~(b)~~ (ii) TPC is not subject to or a party to, any restriction in its constating documents or by-laws, any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement and each of the other Loan Documents to which it is a party or compliance by TPC with the terms, conditions and provisions hereof or thereof or the continuing operation of the Business.

~~(9)~~ **(i) Title to Collateral.** TPC is the registered owner and sole beneficial owner of and has good and marketable beneficial title to and is lawfully possessed of its Property free and clear of all Liens, except Permitted Liens. A complete and accurate listing of its Property has been provided to Hydro, including the Collateral, and TPC has full right to mortgage, pledge, charge and assign to Hydro the Collateral. No Person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding or commitment, for the purchase from NCN or TPC of the Collateral other than Hydro.

~~(10)~~ **(j) Compliance with Laws.** Each of NCN and TPC is in material compliance with all applicable Laws.

~~(11)~~ **(k) No Breach of Contracts.** Schedule C, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date, will contain a complete and accurate list of all agreements to which:

~~(a)~~ (i) NCN and/or TPC is a party in connection with the Corporate Distributions of TPC, the Capital Stock of TPC, the equity interest that NCN has in TPC, TPC's Units and Distributions on TPC's Units;

~~(b)~~ (ii) NCN is a party in connection with or arising out of the Wuskwatim Project creating liabilities or obligations upon any Person over the term of the agreement in excess of $75,000; and

~~(c)~~ (iii) TPC is a party creating liabilities or obligations upon any Person over the term of the agreements in excess of $75,000 or is otherwise material to TPC (collectively, the "**Material Agreements**"). NCN and TPC have provided~~, or will, on or before the Initial Closing Date provide,~~ copies of all Material Agreements, including amendments or additions thereto, to Hydro. On the date of the execution of each Future Material Agreement (as defined below in Section 6.1(11)), Schedule C shall be deemed to be amended to include such Future Material Agreements and such Future Material Agreements shall be deemed to be Material Agreements for the purposes of this Agreement from and after the date of execution without the necessity of any further action by any of the parties hereto. Each Material Agreement is~~, or will on or before the Initial Closing Date be,~~ in full force and effect, unamended (except as disclosed to Hydro), and there exists no default or event, occurrence, condition or act (including the completion of the transactions contemplated under this Agreement and any other Loan Document) which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a default thereunder. Neither NCN nor TPC have violated or breached, in any respect, any of the terms or conditions of any Material Agreement and, to the best of the knowledge of NCN and TPC, all the material covenants to be performed by any other party thereto have been fully performed in all material respects.

~~(12)~~ **(l) Books and Records.** All books and records of TPC have been fully, properly and accurately kept and completed in accordance with GAAP and there are no material inaccuracies or discrepancies of any kind contained or reflected therein.

~~(13)~~ **(m) Tax Liability.** Except for any Taxes which are being diligently contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books:

~~(a)~~ (i) TPC has in a timely manner filed all tax returns, elections, filings and reports with respect to Taxes required by Law to be filed by it and such returns, elections, filings and reports are true, complete and correct;

~~(b)~~ (ii) TPC has paid, or reserved in its financial statements, all Taxes which are due and payable, and has paid all assessments and reassessments and all other Taxes, governmental charges penalties, interest and fines due and payable by it;

~~(c)~~ (iii) TPC has no liability, contingent or otherwise, for Taxes, except Taxes not now due and payable with respect to ordinary operations during the current fiscal period adequate provision for the payment of which has been made; and

~~(d)~~ (iv) TPC has paid as and when due all applicable Taxes and remitted as required by Law all applicable Taxes and deductions and any interest or penalties related thereto.

~~(14)~~ **(n) Shareholder.** NCN is the beneficial owner of all of the Capital Stock of TPC free and clear of all Liens except Permitted Liens. The Capital Stock of TPC is owned by the Chief or a Councillor of NCN, as bare trustee for NCN. No Person has any written or oral agreement, option, understanding or commitment, or any right capable of becoming an agreement, option, understanding, commitment, or right for purchase of any of the Capital Stock of TPC or to receive payment based on the value of any such Capital Stock. The issued and outstanding Capital Stock and Debt (excluding Debt under this Agreement) of TPC and the registered beneficial holders of such Capital Stock and Debt (excluding Debt under this Agreement) will be as described in Schedule D, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date. Hydro acknowledges that the NCN Deed of Assignment shall not be deemed to be a breach of this representation.

~~(15)~~ **(o) Liabilities.** TPC does not have any liabilities, whether accrued, absolute, contingent or otherwise, of any kind or nature whatsoever, except as otherwise disclosed in Schedule E, which will be completed and provided by NCN to Hydro on or before the Initial Closing Date or pursuant to the Loan Documents, and except as incurred after the date hereof in compliance with this Agreement and the Loan Documents.

~~(16)~~ **(p)** **No Event of Default.** No Event of Default has occurred, nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute and Event of Default under the Loan Documents. No default has occurred nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute a default under any one or more of the Material Agreements which could result in the acceleration of amounts owing by NCN or TPC under any such Material Agreements.

~~(17)~~ **(q)** **Financial Information.** The financial statements of TPC furnished to Hydro pursuant to this Agreement have been prepared in accordance with GAAP, consistently applied, and present fairly the financial position of TPC as at the dates thereof and the results of their operations for the periods then ended. All balance sheets, all statements of operations, shareholders' equity and cash flow and all other financial information of TPC furnished pursuant to Section 6.1(a)(1) have been and will for periods following the Initial Closing be prepared in accordance with GAAP consistently applied, and do or will present fairly the consolidated financial position of TPC thereby as at the dates thereof and the results of their operations for the periods then ended.

Each of the representations and warranties contained in this Section 5.1 shall be deemed to be continually repeated by NCN and TPC at the time of each Dividend Credit Advance.

5.2 Survival of Representations and Warranties.

All the representations and warranties of NCN and TPC contained in Section 5.1 shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Dividend Credit Facility has been terminated notwithstanding any investigation made at any time by or on behalf of Hydro.

5.3 Representations by Hydro.

To induce NCN and TPC to enter into this Agreement, Hydro represents and warrants to NCN and TPC that each of the following representations and warrants is true and correct:

~~(1)~~ (a) Hydro is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and each of the other Loan Documents to which it is a party and to perform its obligations ~~hereunder and thereunder.~~this Agreement and the Loan Documents.

~~(2)~~ (b) This Agreement and the Loan Documents to which Hydro is a party have been duly authorized, executed and delivered by Hydro and are legal, valid and binding obligations of Hydro enforceable, against Hydro by NCN and TPC to the extent that NCN or TPC is a party thereto, in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction or, by this Agreement, at the discretion of the Arbitrator.

~~(3)~~ (c) Subject only to obtaining the Authorizations described in Schedule H, the execution and delivery of this Agreement and each of the Loan Documents to which Hydro is a party and the consummation the transactions herein provided for by Hydro will not result in:

~~(a)~~ (i) the breach or violation of any other provisions of or constitute a default under or conflict with or cause the acceleration of any obligation of Hydro under:

~~(i)~~ (A) any contract to which Hydro is a party or by which it, or any of its property, is bound;

~~(ii)~~ (B) any provision of the constating documents, by-laws or resolutions of the board of directors (or any committee thereof) of Hydro;

~~(iii)~~ (D) any judgment, decree, order or award of any court, governmental body or arbitrator having jurisdiction over Hydro; or

~~(iv)~~ (E) any applicable law, statue, ordinance, regulation or rule, including, without limitation, the *Hydro Act*; or

~~(b)~~ (ii) the creation or imposition of any Lien on any investment transaction or any of the property or assets of Hydro.

~~(4)~~ (d) Hydro is a resident of Canada for the purposes of the Income Tax Act (Canada).

~~(5) None of:~~

~~(a) this Agreement;~~

~~(b) any of the other Loan Documents; or~~

~~(c)~~ (e) None of (i) this Agreement; (ii) any of the other Loan Documents; or (iii) any certificate or statement in writing which has been supplied by or on behalf of Hydro and is a document that is required to be delivered to Hydro pursuant to this Agreement or any of the other Loan Documents, contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

~~contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.~~

~~(6)~~ (f) There is no requirement for Hydro to make any filing with, give any notice to or obtain any license, permit, certificate, registration, authorization, consent or approval of any government regulatory authority as a condition to the lawful consummation by Hydro of the transaction contemplated by this Agreement and each other Loan Document to which it is a party, except as described in Schedule H.

Each of the representations and warranties contained in this Section 5.3 shall be deemed to be continually repeated by Hydro at the time of each Dividend Credit Advance.

5.4 Survival of Representations and Warranties.

All the representations and warranties of Hydro contained in Section 5.3 shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Dividend Credit Facility has been terminated, notwithstanding any investigation made at any time by or on behalf of NCN or TPC.

ARTICLE VI
COVENANTS OF NCN AND TPC

6.1 Affirmative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Dividend Credit Facility Commitment under this Agreement, and unless Hydro shall otherwise consent, NCN and TPC shall:

~~(1) **Financial Reporting and Deliveries.** Cause to be delivered to Hydro the following documents:~~

~~Annual Financial Statements~~

~~(a)~~ **(a) Financial Reporting and Deliveries.** Cause to be delivered to Hydro as soon as available, and in any event within one hundred and twenty (120) days after the end of each Financial Year, the audited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC for such Financial Year, prepared in accordance with GAAP and subject to an unqualified opinion of the Auditors;

~~Quarterly Financial Statements~~

~~(b) as soon as available, and in any event within sixty (60) days after the end of each Financial Quarter (excluding the last Financial Quarter of a Financial Year), the unaudited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC, prepared in accordance with GAAP;~~

~~(2)~~ **(b) Additional Reporting and Deliveries**. Cause to be delivered to Hydro, the following documents, in form and substance satisfactory to Hydro acting reasonably:

~~(a)~~ (i) a copy of each management letter or report submitted to the board of directors (or any committee thereof) or senior management of TPC by the Auditors in connection with any annual, interim or special audit made by them of the books of TPC, together with the related response of TPC to be delivered promptly upon the issuance of the response by TPC;

~~(b)~~ (ii) promptly after the occurrence of any Event of Default, a statement of NCN setting forth the details of such Event of Default and the action which NCN and/or TPC propose to take or have taken with respect thereto;

~~(c)~~ (iii) promptly after the commencement thereof, Notice of Claims which have been commenced against NCN or TPC (notice of which has been served on NCN or TPC), or to the best of the knowledge of NCN or TPC, are pending or threatened against NCN or TPC for amounts which exceed $75,000 in the aggregate at any time or affect any of the Collateral;

~~(d)~~ (iv) promptly after the occurrence of any material development with respect to any Claims referred to in Section 6.1(2)(c), and in any event within three (3) Business Days after NCN or TPC obtains knowledge of the occurrence thereof, Notice thereof to Hydro, and, to the extent Hydro requests them, copies of all documentation relating thereto; and

~~(e)~~ (v) such other information and reports relating to TPC, the Collateral or the Business or NCN's interest in TPC, as Hydro may from time to time reasonably request.

~~(3)~~ **(c) Existence**. Preserve and maintain TPC's corporate existence.

~~(4)~~ **(d) Compliance with Laws**. Comply, in all material respects with the requirements of all applicable Laws.

~~(5)~~ **(e) Payment of Taxes, Claims and Governmental Licence Fees**. Pay and discharge in respect of TPC, before the same shall become delinquent:

~~(a)~~ (i) all Taxes, governmental assessments, charges or levies and Claims imposed upon it or upon any of its Property;

~~(b)~~ (ii) all lawful Claims which, if unpaid, might by Law become a Lien upon its Property, in each case except for any such Tax, assessment, charge, levy or Claim which would result in a Lien which is a Permitted Lien; and

~~(c)~~ (iii) all fees payable to Governmental Entities or other authorities in connection with all governmental licences issued to and held by TPC (if any).

~~(6)~~ **(f) Keeping of Books**. Keep or cause to be kept, proper books, records and accounts, in which full and correct entries shall be made of all of TPC's financial transactions in accordance with GAAP.

~~(7)~~ **(g) Visitation and Inspection**. If, in the reasonable opinion of Hydro, an Event of Default has or may have occurred, at any reasonable time or times and upon reasonable prior notice given to NCN and TPC by Hydro, permit Hydro or any of its authorized representatives, full and reasonable access to the premises of NCN and TPC and obtain any consents and waivers from any Person necessary, in the reasonable opinion of Hydro to ensure such access, for the purposes of inspecting (and, where required, taking copies of) the respective business, financial and computer records of NCN (but relating to the Wuskwatim Project only) and TPC and to discuss the respective business, financial and computer records of NCN (but relating to the Wuskwatim Project only) and TPC, and compliance by NCN and TPC with the terms of this Agreement and the other Loan Documents (to the extent that each is a party thereto), with the management and Auditors thereof.

~~(8)~~ **(h) Protect Hydro Liens**. At all times take all action and supply Hydro with all such information necessary to allow Hydro to create, maintain, perfect, protect and preserve the Liens provided for under the Security Documents and confer upon Hydro the security interest intended to be created thereby.

~~(9)~~ (i) **Payments**. Pay all amounts of principal, interest, costs and expenses in the manner, on the dates, at the times and at the places specified in this Agreement or under any other Loan Document, but subject to the provisions of Section 8.2 in respect of costs and expenses.

~~(10)~~ (j) **Payment of Preferred Claims**. Pay, as and when due, any and all amounts which may result in a Lien on the Collateral under applicable Law (other than a Permitted Lien) whether or not such Lien is entitled to priority over the Liens in favour of Hydro under the Security Documents.

~~(11)~~ (k) **Loan Documents.** Execute and deliver to Hydro the Loan Documents.

~~(12)~~ (l) **Material Agreements**. Comply with the provisions of all of the Materials Agreements. In respect of each Material Agreement executed by NCN and/or TPC after the date hereof (each a "**Future Material Agreement**"), provide to Hydro, a certified copy of each Future Material Agreement.

~~(13)~~ (m) **Notice of Defaults.** Immediately notify Hydro:

~~(a)~~ (i) of any Event of Default or of any event, occurrence, condition or act which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become an Event of Default, or of any material default (either by NCN or TPC) under any Material Agreement or of any event which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a material default under or would otherwise allow the termination of any Material Agreement, and thereafter provide Hydro with all information reasonably requested by Hydro from time to time concerning the status thereof;

~~(b)~~ (ii) on becoming aware of the occurrence of any litigation, dispute, arbitration, proceeding, labour or industrial dispute the result of which if determined adversely would have a Material Adverse Business Effect on the ability of NCN and/or TPC to perform their respective obligations under this Agreement and the other Loan Documents and thereafter provide Hydro with all information reasonably requested by Hydro concerning the status thereof.

~~(14)~~ (n) **Further Assurances**. Upon request of Hydro, duly execute and deliver or cause to be duly executed and delivered to Hydro such further instruments and other documents, and do and cause to be done such further acts as may be necessary or desirable in the opinion of Hydro, acting reasonably, to carry out more effectively the provisions and purposes of the Loan Documents.

6.2 Negative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Dividend Credit Facility Commitment under this Agreement and unless Hydro, as the case may be, shall otherwise consent, NCN and TPC agree that:

~~(1)~~ (a) **Business Activity.** TPC shall not engage in any business activity except the Business.

~~(2)~~ (b) **Liens**. No Liens shall be created, incurred, assumed or suffered to exist, on any of TPC's Property including the Collateral and the Capital Stock of TPC other than Permitted Liens. For greater certainty this does not prohibit the NCN Deed of Assignment.

~~(3)~~ (c) **Disposal of Property.** None of the Collateral shall be disposed of by TPC.

~~(4)~~ (d) **Debt**. Except with the prior consent of Hydro, TPC shall not allow any Debt of TPC to be created, incurred, assumed or suffered to exist, directly, or contingently or otherwise, other than:

~~(a)~~ (i) Debt to Hydro;

~~(b)~~ (ii) unsecured current liabilities incurred and payable in the ordinary course of the Business and not represented by any note, bond or debenture; or

~~(c)~~ (iii) Purchase Money Debt, provided that the payments under such Purchase Money Debt does not exceed an aggregate amount in any one year period of $15,000.

~~(5)~~ **(e) Mergers**. TPC shall not reorganize, amalgamate, merge, consolidate or otherwise enter into any form of business combination with any other Person.

~~(6)~~ **(f) Guarantees and Indemnities**. TPC shall not guarantee or indemnify or give financial assistance or incur any contingent liability in respect of any Debt or any other obligations or liabilities of any other Person at any time other than pursuant to the Guarantee.

~~(7)~~ **(g) Dividends.** TPC shall not:

~~(a)~~ (i) declare or pay any dividends or any distributions after Hydro has provided notice to TPC that an Event of Default has occurred; nor

~~(b)~~ (ii) declare or pay any dividends or other distributions, in any other circumstances if, after declaring or paying such dividend or other distribution, TPC would not be able to meet its obligations under the Loan Documents.

~~(8)~~ **(h) Financial Year and Auditors**. TPC shall not change its Financial Year end or its Auditors.

~~(9)~~ ~~**Change in Constating Documents or Capital Stock.**~~

~~(a) There shall be no change in the constating documents or by-laws of TPC as delivered to Hydro which would:~~

~~(i) amend the authorized shares or other equity securities of TPC; or~~

~~(ii) otherwise be detrimental to the rights or interests of Hydro under any of the Loan Documents;~~

~~(b) Issue~~**(i) Change in Constating Documents or Capital Stock**. There shall be no change in the constating documents or by-laws of TPC as delivered to Hydro which would amend the authorized shares or other equity securities of TPC or otherwise be detrimental to the rights or interests of Hydro under any of the Loan Documents or issue any Capital Stock in TPC that would cause an Event of Default to occur or would cause a Change of Control of TPC.

~~(10)~~ **(j) Material Agreements**. There shall be no amendment, supplement, termination or waiver, or entering into of any forbearance from exercising any rights with respect to, any of the terms of any Material Agreement in a manner which would cause a Material Adverse Business Effect or an Event of Default hereunder.

~~(11)~~ **(k) Change of Control**. There shall be no Change of Control.

~~(12) **Change of Registered Owner.**~~

(l) Change of Registered Owner. Change the registered owner of the Capital Stock of TPC to any person other than the Chief or a Councillor of NCN, as bare trustee for NCN, or change the form of bare trustee declaration prior to obtaining the written consent of Hydro to the change.

6.3 Cross-Default.

Any Event of Default (as defined in the TPC Financing Agreement) by TPC shall be deemed to be an Event of Default hereunder.

ARTICLE VII
SECURITY

7.1 Security.

Each of NCN and TPC shall execute and deliver, the Security Documents to which it is a party with each of the Security Documents to be in form and substance satisfactory to Hydro, acting reasonably, as and when required hereunder or under the Loan Documents as continuing collateral security in the Collateral for the due, prompt and complete payment, performance and satisfaction by TPC of all of NCN's indebtedness, liabilities and obligations of every nature whatsoever (whether present or future, direct or indirect, absolute or contingent, matured or unmatured, at any time due or accruing due, whatsoever and howsoever incurred, including any ultimate unpaid balance thereof, in any currency, and whether incurred prior to, at the time or subsequent to the execution of this Agreement) to Hydro, in connection with this Agreement and the other Loan Documents (collectively the "**Obligations**").

Notwithstanding anything to the contrary herein, this Agreement shall be interpreted in all respects having regard for the fact that, and the Security Documents shall provide that, (a) Hydro has a first charge security interest on TPC's Units and the Distributions on TPC's Units and any interest related to TPC's Units and the said Distributions, and (b) Hydro's sole recourse for payment of the Obligations shall be to the Collateral in accordance with the provisions of this Agreement, and for greater certainty, it shall have no right to sue TPC or NCN on any personal covenant to pay all or any of the Obligations, including without limitation, under the Guarantee.

7.2 Registrations.

~~(1)~~ Hydro, in its sole discretion, may register, file or record the Liens constituted by the Security Documents in all jurisdictions where such registration, filing, or recording is necessary or of advantage to the creation, perfection, preservation or protection of such Liens.

7.3 Renewals.

~~(2)~~ Hydro may renew such registrations, filings and recordings from time to time as and when required or of advantage, in the sole discretion of Hydro, to keep them in full force and effect. NCN and TPC acknowledge that the forms of the Security Documents have been prepared based upon the laws of the jurisdictions indicated therein as being applicable thereto in effect at the date hereof and that such Laws may change. NCN and TPC agree that, following prior notice to and consultation with NCN and TPC, upon direction from Hydro, Hydro shall have the right to require that the forms of the Security Documents be amended, restated or supplemented, to reflect any changes in such Laws, whether arising as a result of statutory amendments, court decisions or other similar changes, in order to confer upon Hydro the Liens in the Collateral intended to be created by the Security Documents, in the sole discretion of Hydro. For greater certainty, nothing in this Agreement can be used by Hydro, TPC or NCN or by any other Person to expand or reduce or otherwise change the scope of the Property comprising the Collateral herein defined or to confer upon Hydro a right to sue TPC or NCN on a personal covenant to pay all or any of the Obligations, or to require any guarantees (except the Guarantee), indemnities or covenants from NCN or any other Person in respect of the Obligations or otherwise.

ARTICLE VIII
EVENTS OF DEFAULT

8.1 Events of Default.

If any of the following events, conditions or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) NCN shall fail to pay any portion of the principal or interest or any fees or other amounts due hereunder or under any of the other Loan Documents on the date when due hereunder or thereunder and such amount remains unpaid for a period of six (6) Business Days after Hydro notifies NCN that the amount is overdue; provided however, that this provision shall be read in conjunction with the provisions in this Agreement, the TPC Financing Agreement and the other Loan Documents hereunder and thereunder which provide that, for so long as TPC and NCN are otherwise in good standing under the provisions of this Agreement, the TPC Financing Agreement and the other Loan Documents hereunder and thereunder, all such payments to Hydro are to made solely through the irrevocable assignment and direction to Hydro of the Distributions on TPC's Units (or a portion thereof, as applicable under the priority provisions of the TPC Financing Agreement) prior to the Maturity Date (and, in certain circumstances, after the Maturity Date), and from no other source, such that for so long as the Distributions are so assigned by TPC (as collateral security for the Guarantee) and are paid over to Hydro as and when declared by the General Partner of the Limited Partnership pursuant to the irrevocable assignment and direction in favour of Hydro, NCN shall be deemed to be in compliance with its covenants to pay for all purposes hereunder and under the other Loan Documents. The parties hereto acknowledge that neither TPC nor NCN control the timing or amount of such Distributions, and as such, there may be periods of time during which there are no or few Distributions to be paid over to Hydro in accordance with the irrevocable assignment and direction to Hydro, and this shall not be construed to be an Event of Default hereunder;

(b) any representation or warranty or certification made or deemed to be made by any NCN or TPC or pursuant to or in connection with any of the Loan Documents delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(c) NCN or TPC shall fail to perform or observe any other term, covenant or agreement contained in any of the Loan Documents on its part to be performed or observed and such failure shall remain unremedied for fifteen (15) Business Days (the "**Cure Period**") after written notice thereof shall have been given to NCN and TPC by Hydro; provided that the length of the Cure Period shall be extended by Hydro in its unfettered discretion where NCN and TPC demonstrate to Hydro that the breach is not capable of being cured within fifteen (15) Business Days but provides Hydro, within fifteen (15) Business Days, with a plan for curing the breach within sixty (60) calendar days and in good faith implements such plan;

(d) any of the Loan Documents, at any time, is not or ceases to be valid or enforceable in whole or in part, or if any Lien intended to be created by any of the Security Documents is not or ceases to be a valid and perfected Lien having the ranking or priority contemplated thereby, or if the validity or enforceability of any of the Loan Documents or the validity or perfection of any such Lien shall be contested by any party thereto or any other Person (unless such contestation by such party or other Person is being opposed diligently, in good faith and by proper legal proceedings by Hydro with the assistance of NCN and TPC and Hydro covenants to oppose such contestation in good faith, where in its discretion, there is a reasonable prospect of success), or if any Person (other than Hydro or the Limited Partnership) obtains any interest in the Collateral or any part thereof (except Permitted Liens); provided however, that this provision shall only be invoked where Hydro, acting reasonably, has determined that its inability to enforce the said Lien with its intended ranking or priority cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected notwithstanding that NCN and TPC have provided a written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said Lien with its intended ranking or priority;

(e) with respect to Debt of TPC under any one or more agreements other than the Debt under the Loan Documents,

(i) TPC shall fail to pay any principal, interest or other amount pursuant to the agreements governing such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) when such amount becomes due and payable (whether by scheduled maturity, required repayment, acceleration, demand or otherwise) and such failure shall continue after any applicable grace period specified in such agreement or agreements; or

(ii) any other event, condition or circumstance shall occur and shall continue after any applicable grace period specified in such agreement or agreements, if the effect of such event, condition or circumstance is to accelerate the maturity of such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency); or

(iii) other Debt of TPC in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) shall be declared to be due and payable prior to the stated maturity thereof under any such agreement or agreements;

(f) the occurrence of any default, or any event or condition which, with the giving of notice or passage of time, or both would constitute a default under any Material Agreement and such default shall continue unremedied after any applicable grace period specified in such Material Agreement;

(g) NCN or TPC shall:

(i) become insolvent;

(ii) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(iii) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iv) institute or have instituted against it any proceeding seeking (x) to adjudicate it a bankrupt or insolvent, (y) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors, or (z) the entry of an order for relief or the appointment of a receiver, interim receiver, receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property, and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within forty five (45) days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; provided however, that in the event that a third party manager or co-manager is appointed for NCN, this shall not constitute an Event of Default hereunder provided that the third party manager or co-manager abides by the terms and conditions of this Agreement; or

(v) take any corporate action to authorize any of the foregoing actions;

(h) a Notice is sent to NCN or TPC from any creditor with respect to the intention of such creditor to enforce a Lien on:

(i) any of the Collateral; or

(ii) any Property of TPC (other than the Collateral) unless such Notice is being contested in good faith by appropriate legal proceedings and such Notice has not resulted in, or does not involve, any immediate danger of the sale, forfeiture or loss of any of the Property of TPC that is the subject of such Notice; or

(iii) the Capital Stock of TPC;

(i) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Entity which may be reasonably likely to require TPC to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against TPC, and either:

(i) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

(ii) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(j) the audited financial statements of TPC in respect of any Financial Year are qualified in any material adverse respect by the Auditors;

(k) the occurrence of a Change of Control;

(l) the loss, suspension or failure to renew any licence or permit held by TPC or any agreement to which TPC is a party the effect of which would prohibit or otherwise restrict TPC from conducting the Business;

(m) TPC is enjoined or restrained in any material way by an order of any Governmental Entity, arbitrator or board in Canada or elsewhere from conducting the Business;

(n) the occurrence of a Material Adverse Business Effect;

(o) the occurrence an Event of Default committed by TPC (as such term is defined in the TPC Financing Agreement); or

(p) the occurrence of any event, condition or circumstance which, with the giving of notice or passage of time or both, would constitute an Event of Default, after the expiration of, in the case of a Loan Document, the applicable Cure Period or in the case of any other agreement, the applicable cure period (if any) thereunder;

then, and in any such event, Hydro shall be entitled by written notice to NCN and TPC to:

~~(a)~~ (i)terminate the obligation of Hydro to make further Dividend Credit Advances under the Dividend Credit Facility; and/or

~~(b)~~ (ii) demand repayment of the Total Outstandings owed by NCN to Hydro under the Dividend Credit Facility, whereupon the Total Outstandings and other amounts payable thereunder shall become forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by NCN and TPC except such notices as may be required under applicable Laws. Provided, however that Hydro shall only have recourse to the Collateral for repayment of the Obligations and further provided, however, that upon any Event of Default specified in Section 8.1(g), the obligation of Hydro to make Dividend Credit Advances hereunder shall automatically terminate.

8.2 Expenses of Hydro.

Upon the occurrence of any Event of Default which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Default. All reasonable expenses, costs and charges incurred by or on behalf of Hydro in connection with:

(a) any remedial action taken pursuant to this Section; or

(b) the realization of the Collateral, including all reasonable fees, court costs, receiver's or agent's remuneration and other expenses of taking possession of, repairing, protecting, insuring, preparing for disposition, realizing, collecting, selling, transferring, delivering or obtaining payment of the Collateral, in all cases shall be added to and form a part of the Obligations, but subject always to the provisions that Hydro's sole recourse for payment of the Obligations shall be to the Collateral, as set out herein. For greater certainty, for so long as there is no Event of Default hereunder, Section 5.14 of the PDA shall govern the payment of Hydro's costs and expenses properly recoverable hereunder.

8.3 Remedies Cumulative.

The remedies provided for in this Agreement and each of the Loan Documents are cumulative and do not exclude any other right or remedy provided by Law (except that there shall be no right of Hydro to sue TPC or NCN on any personal covenant to pay, it being acknowledged that Hydro's sole recourse is to the Collateral).

8.4 Allocations.

For greater certainty, the parties agree that any expenses or costs that are, by the terms of this Agreement or under the other Loan Documents, reimbursable to Hydro shall be allocated to the Dividend Credit Facility.

ARTICLE IX
PAYMENTS, COMPUTATIONS AND INDEMNITIES

9.1 Timing of Payments under this Agreement.

~~(1)~~ Unless otherwise expressly provided in this Agreement~~,~~:

(a) NCN shall make any payment required to be made by it to Hydro by depositing the amount of such payment in Hydro's Account not later than 11:00 a.m. (Winnipeg time) on the date such payment is due~~.~~; and

~~(2) Unless otherwise expressly provided in this Agreement,~~ (b) Hydro shall make any Dividend Credit Advance or other payment to NCN ~~hereunder~~ under this Agreement by crediting or causing the crediting of the account of NCN directed by NCN in the applicable Borrowing Notice with the amount of such Dividend Credit Advance on the date such Dividend Credit Advance is to be made.

9.2 Payments on Non-Business Days.

Whenever any payment hereunder shall be stated to be due on a day other than a Business Day, such payment shall be made on the next succeeding Business Day, and such extension of time shall not be included in the computation of interest unless an Event of Default has occurred and is continuing, in which event such extension of time shall be included in the computation of interest.

9.3 Overdue Amounts.

All amounts owed by NCN which are not paid when due (whether at stated maturity, on demand, by acceleration or otherwise) shall bear interest (both before and after judgment), from the date on which such amount is due until such amount is paid in full, payable on demand, at a rate per annum equal at all times, to the applicable rate specified in Section 3.3.

9.4 Application of Payments, Repayments and Prepayments.

All amounts received by Hydro from or on behalf of NCN, including a realization of the Collateral, and not previously applied pursuant to this Agreement shall be applied:

(a) first, in reduction of NCN's obligation to pay any costs or expenses which are due and owing to Hydro, and reimbursable or indemnity amounts or Losses which have been determined by a court of competent jurisdiction or by arbitration to be due and owing to Hydro;

(b) second, in reduction of NCN's obligation to pay any unpaid interest accrued on the principal amount of Dividend Credit Advances;

(c) third, in reduction of such NCN's obligation to pay any amounts due and owing on account of the principal amount of all Dividend Credit Advances;

(d) fourth, to be held in escrow by Hydro in an interest-bearing account on account, and up to the amount, of any written claim by Hydro then issued and outstanding seeking reimbursement or indemnity hereunder for Losses, pending determination by a court of competent jurisdiction or by arbitration as to the amount (if any) which is due and owing to Hydro hereunder (in which event, such funds and any interest earned thereon shall be dealt with in accordance with the order of the court of competent jurisdiction or arbitrator, as the case may be); and

(e) fifth, to NCN or such other Persons as may lawfully be entitled to the remainder, or as any court of competent jurisdiction may otherwise direct.

9.5 Computations of Interest and Fees.

~~(1)~~ (a) All computations of interest shall be made by Hydro, based on the semi-annual interest computation (and not the number of days in the six (6) month period) and on the basis of a year of 365 days.

~~(2)~~ (b) Notwithstanding any provision to the contrary contained in this Agreement, in no event shall the aggregate "interest" (as defined in Section 347 of the *Criminal Code* (Canada), as the same may be amended, replaced or re-enacted from time to time) payable under this Agreement exceed the maximum amount of interest on the "credit advanced" (as defined in that Section) under this Agreement lawfully permitted under that Section and, if any payment, collection or demand pursuant to this Agreement in respect of "interest" (as defined in that Section) is determined to be contrary to the provisions of that Section, such payment, collection or demand shall be refunded to NCN. For purposes of this Agreement, the effective annual rate of interest shall be determined in accordance with generally accepted actuarial practices and principles over the term that the relevant Dividend Credit Advance is outstanding on the basis of annual compounding of the lawfully permitted rate of interest and, in the event of any dispute, a certificate of a Fellow of the Canadian Institute of Actuaries appointed by Hydro will be conclusive for the purposes of such determination.

~~(3)~~ (c) Each determination by Hydro of any amount payable hereunder by NCN shall be *prima facie* evidence of the amount payable for all purposes absent error.

9.6 Indemnity for Change in Circumstances.

~~(1) If with respect to Hydro:~~

~~(a)~~ (a) If any change in Law, or any change in the interpretation or application by any Governmental Entity of any Law occurring or becoming effective after the date ~~hereof; or~~of this Agreement or any compliance by Hydro with any direction or requirement having the force of Law) of any Governmental Entity made or becoming effective after the date of this Agreement, causes Loss to Hydro by:

~~(b) any compliance by Hydro with any direction or requirement having the force of Law) of any Governmental Entity made or becoming effective after the date hereof,~~

~~in either case shall have the effect of causing Loss to Hydro by:~~

(i) increasing the actual cost to Hydro of performing its obligations under this Agreement or in respect of any Dividend Advance;

(ii) reducing any amount otherwise properly payable to Hydro under this Agreement or in respect of any Dividend Advance by any amount that Hydro deems material acting reasonably (other than pursuant to Section 9.5(2));

then Hydro may give notice to NCN specifying the nature of the event giving rise to such Loss and NCN shall, within twenty (20) Business Days of demand, pay such amounts as Hydro may specify is necessary to compensate Hydro for such Loss. A certificate as to the amount of any such Loss, submitted in good faith by Hydro to NCN shall be *prima facie* evidence of the amount of such Loss for all purposes, absent error.

~~(2)~~ (b) Except as required by applicable Law, NCN and TPC shall make all payments under this Agreement to Hydro without deducting or withholding of any Taxes. To the extent that deduction or withholding of Taxes is required by applicable Law, NCN and TPC will:

~~(a)~~ (i) immediately notify Hydro of such requirement;

~~(b)~~ (ii) pay to the appropriate authority the full amount required to be so withheld or deducted before penalties attach thereto or interest accrues thereon;

~~(c)~~ (iii) promptly forward to Hydro an official receipt or other documentation reasonably satisfactory to Hydro evidencing such payment to such authority; and

~~(d)~~ (iv) pay to Hydro an additional amount so that Hydro receives the full amount it would have received had no such deduction or withholding been required.

If any Taxes are directly asserted against Hydro with respect to any payment under this Agreement, Hydro may pay such Taxes and NCN shall promptly pay such additional amount (including any penalties, interest and expenses) necessary so that the net amount received by Hydro after the payment of such Taxes, including any Taxes on such additional amounts, shall equal the amount Hydro would have received had Hydro not paid such Taxes.

NCN will indemnify Hydro for all incremental Taxes, interest or penalties that Hydro must pay if NCN fail to deduct or withhold any Taxes when due or to send Hydro the required receipts or other documentation.

Hydro acknowledges that in respect of this Section 9.6(~~2~~b), Taxes shall not include any income taxes that may be payable by Hydro. Hydro shall remain solely obligated to pay and shall save TPC and NCN harmless from any income taxes that may be asserted against Hydro or payable by Hydro, including with respect to any payments or amounts received or made under this Agreement.

9.7 Indemnity.

~~(1)~~ (a) NCN hereby agrees to indemnify, exonerate and hold Hydro and its officers, directors, employees, agents and other representatives (in this Section 9.7(1), the "**Indemnified Parties**") free and harmless from and against any and all Claims, demands, actions, causes of action, suits, losses, costs (including all documentary, recording, filing, mortgage duties), charges, liabilities and damages, and expenses in connection therewith (irrespective of whether such Indemnified Party is a party to the action for which such indemnification hereunder is sought), and including reasonable legal fees and disbursements (collectively, in this Section 9.7(1), the "**Indemnified Liabilities**") paid, incurred or suffered by, or asserted against, the Indemnified Parties or any of them or, with respect to, or as a direct or indirect result of:

(i) any transaction financed or to be financed in whole or in part, directly or indirectly, with the proceeds of any Dividend Credit Advances obtained hereunder; or

(ii) the execution, delivery, performance or enforcement of this Agreement or any Loan Documents, except for such Indemnified Liabilities that a court of competent jurisdiction determines or rules to be on account of the relevant gross negligence or willful misconduct of the Indemnified Party or any Person for whom such Indemnified Party is responsible at law [in which event, such Party shall indemnify TPC and its officers and directors and NCN and its Chief and Councillors (to the extent that each of NCN's Chiefs and Councillors is liable at law in his or her respective capacity as part of Chief and Council) for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct].

~~(2)~~ (b) All obligations provided for in this Section 9.7 shall not be reduced or impaired by any investigation made by or on behalf of Hydro.

~~(3)~~ (c) If, for any reason, the obligations of NCN pursuant to this Section 9.7 shall be unenforceable, NCN agrees to make the maximum contribution to the payment and satisfaction of each obligation that is permissible under Law, except to the extent that a court of competent jurisdiction determines such obligations arose on account of the gross negligence or willful misconduct or any Person for whom such Indemnified Party is responsible at law [in such event such Party shall indemnify TPC and its officers and directors and NCN and its Chief and Councillors (to the extent that each of NCN's Chiefs and Councillors is liable at law in his or her respective capacity as part of Chief and Council), for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct].

9.8 <u>Contribution.</u>

If any provision in any of the Loan Documents providing for indemnification by NCN (the "**Indemnitor**") in favour of Hydro or any of the Indemnified Parties (as defined in Section 9.7) (the "**Indemnitee**") is found by reason of the occurrence of an event, other than the gross negligence or wilful misconduct of the Indemnitee, to be unenforceable by a court of competent jurisdiction in a final judgment that has become non-appealable, then the Indemnitor shall contribute to the amount paid or payable by the Indemnitee which is subject to the indemnification provision in such proportion as is appropriate to reflect not only the relative benefits received by the Indemnitor on the one hand and the Indemnitee on the other hand but also the relative fault of the Indemnitor and the Indemnitee but only to the extent that such contribution is consistent with the terms of the final judgment. The rights of contribution herein provided shall be in addition to and not in derogation of any other right to contribution which the Indemnitee may have under this Agreement or applicable Laws.

9.9 <u>Confirmation of Limited Recourse.</u>

For greater certainty, Hydro acknowledges that nothing in this Article IX shall in any way detract from the limited recourse of Hydro's security and remedies hereunder, as set out in Section 7.1.

ARTICLE X
DISPUTE RESOLUTION

10.1 **Dispute Resolution.**

Each of the parties to the Agreement agrees that any disputes or claims arising out of this Agreement shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the PDA and it shall not bring any action in respect of any matter arising hereunder, other than pursuant to Article XXI of the PDA, against any other party.

ARTICLE XI
GENERAL PROVISIONS

11.1 **Notices.**

~~(1)~~ All notices provided for in this Agreement or in the other Loan Documents shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule F hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

~~(2)~~ Each Borrowing Notice and Repayment Notice shall be irrevocable and binding on NCN.

11.2 Time of the Essence.

Time shall be of the essence of this Agreement.

11.3 Third Party Beneficiaries.

Each party hereto intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any Person, other than the parties hereto and the Persons contemplated in Section 9.7 or Section 11.7, and no Person, other than the parties hereto and the Persons contemplated in Section 9.7 or Section 11.7, shall be entitled to rely on the provisions hereof in any action, suit, proceeding, hearing or other forum. For greater certainty, nothing in this Section 11.3 is intended to prevent or restrict the Taskinigahp Trust from receiving Dividends declared by the Board of Directors of TPC pursuant to the NCN Deed of Assignment subject always to TPC's compliance with the covenants, representations and warranties of this Agreement.

11.4 Enurement.

This Agreement shall enure to the benefit of and be binding upon the parties hereto. This Agreement shall be binding upon any assigns and enure to the benefit of any permitted assigns.

11.5 Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

11.6 Knowledge.

Where any representation or warranty contained in this Agreement or any other Loan Document is expressly qualified by reference to the "best of the knowledge" of NCN or TPC, or where any other reference is made herein or in any Loan Document to "the knowledge" of NCN or TPC, it shall be deemed to refer to the best of the knowledge of the Chief and Council of NCN and the members of the board of directors of TPC, respectively.

11.7 Assignment.

Neither this Agreement nor the rights and obligations hereunder shall be assignable or transferable by NCN or TPC or Hydro, except that Hydro may assign this Agreement to any Affiliate, on the condition that notwithstanding the Assignment, Hydro will remain jointly and severally liable with the said Affiliate, for compliance with the covenants of Hydro under this Agreement.

11.8 Non-Merger.

Except as otherwise expressly provided in this Agreement, the covenants, representations and warranties of the parties contained in this Agreement and the other Loan Documents shall not merge on and shall survive the Initial Closing and Final Investment Closing and the making of any Dividend Credit Advance, and notwithstanding such Initial Closing and Final Investment Closing or Dividend Credit Advance, or any investigation made by or on behalf of any party, shall continue in full force and effect. Neither the Initial Closing and Final Investment Closing nor the making of any Dividend Credit Advance shall prejudice any right of one party against any other party in respect of anything done or omitted hereunder or under any of the other Loan Documents or in respect of any right to damages or other remedies.

[Execution pages follow]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed on the date first above written.

NISICHAWAYASIHK CREE NATION

~~Jerry Primrose~~Marcel Moody, Chief

~~Jimmy Hunter~~ Ron Spence, ~~Councillor~~ Deputy Chief

~~D'Arcy~~Patrick Linklater, Councillor

Shirley L. Linklater, Councillor

~~Agnes M. Spence~~Bonnie Linklater, Councillor

~~William Elvis Thomas~~Willie Moore, Councillor

Joe Moose, Councillor

TASKINIGAHP POWER CORPORATION

Per:

Name: ~~Jerry Primrose~~
Title: President

Per:

Name: ~~William Elvis Thomas~~
Title: Vice-President

Per:

Name: Shirley L. Linklater
Title: Secretary-Treasurer

THE MANITOBA HYDRO-ELECTRIC BOARD

Per:

Name: ~~Robert B. Brennan~~
Title: President and Chief Executive Officer

Per:

Name: ~~Robert D. Bettner~~
Title: Assistant Corporate Secretary

SCHEDULE A

REPAYMENT NOTICE

TO: THE MANITOBA HYDRO-ELECTRIC BOARD (“Hydro”)

FROM: NISICHAWAYASIHK CREE NATION (“NCN”)

This Repayment Notice is delivered to you pursuant to Section 2.6 of the financing agreement (the “Amended and Restated NCN Financing Agreement”) dated ~~●, 2006~~Effective April 1, 2015 between NCN, as borrower, Taskinigahp Power Corporation and Hydro, as lender. All capitalized terms used in this Repayment Notice and defined in the NCN Financing Agreement shall have the meanings defined in the NCN Financing Agreement.

1. NCN hereby gives notice of repayment as follows:

   (a) Date of repayment:

   (b) Type of Advance:

   (c) Amount of principal being repaid:

NISICHAWAYASIHK CREE NATION

Chief

Councillor

Councillor

Councillor

Councillor

Councillor

SCHEDULE B

BORROWING NOTICE

To: THE MANITOBA HYDRO-ELECTRIC BOARD ("Hydro")

From: NISICHAWAYASIHK CREE NATION ("NCN")
TASKINIGAHP POWER CORPORATION ("TPC")

This Borrowing Notice is delivered to you pursuant to Section 3.2 of the amended and restated financing agreement (the "NCN Financing Agreement") dated ~~•, 2006~~as of April 1, 2015 between NCN, as borrower, TPC and Hydro, as lender. All capitalized terms used in this Borrowing Notice and defined in the NCN Financing Agreement shall have the meaning defined in the NCN Financing Agreement.

1. NCN hereby requests an Dividend Credit Advance as follows:

   (a) Date of Dividend Credit Advance:

   (b) Amount of Dividend Credit Advance:

   (c) Payment Instructions:

2. NCN and TPC hereby certify that:

   (a) All of the representations and warranties of NCN and TPC contained in Section 5.1 of the NCN Financing Agreement are true and correct in all material respects on and as of the date hereof as though made on and as of the date hereof (other than those representations and warranties in Section 5.1 which are specifically limited to a particular date) and except as disclosed in writing to, and accepted in writing by Hydro.

   (b) All of the covenants of NCN and TPC contained in Article VI of the NCN Financing Agreement together with all of the conditions precedent to an Advance in Article IV of the NCN Financing Agreement (to the extent they are within NCN's and/or TPC's control) have been complied with or met in all material respects, except as disclosed in writing to, and accepted in writing by Hydro.

(c) No Event of Default has occurred and is continuing on the date hereof nor will any Event of Default occur as a result of the aforementioned Dividend Credit Advance, except as disclosed in writing to, and accepted in writing by Hydro.

DATED:

NISICHAWAYASIHK CREE NATION

Chief

Councillor

Councillor

Councillor

Councillor

Councillor

TASKINIGAHP POWER CORPORATION

Per:
Name:
Title:

Per:
Name:
Title:

SCHEDULE C

MATERIAL AGREEMENTS

~~To be provided~~Provided on Initial Closing

SCHEDULE D

ISSUED AND OUTSTANDING CAPITAL STOCK AND DEBT

~~To be provided~~Provided on Initial Closing

SCHEDULE E

LIABILITIES

~~To be provided~~Provided on Initial Closing

SCHEDULE F

ADDRESS FOR NOTICE

Nisichawayasihk Cree Nation
Attention: Chief and Council
General Delivery
Nelson House, MB
R0B 1A0

Fax Number: (204) 484-2392

Taskinigahp Power Corporation
Attention: President
General Delivery
Nelson House, MB
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Manitoba Hydro
Attention: General Counsel
~~3rd Floor – 820 Taylor Avenue~~
~~Winnipeg, MB R3C 2P4~~360 Portage AvenueWinnipeg, MB

Fax Number: (204) ~~474~~360-4947

SCHEDULE G

LIST OF SECURITY DOCUMENTS

1. TPC Limited Recourse Guarantee
2. TPC Security Agreement
3. Pledge of TPC's Units
4. Limited Power of Attorney granted by TPC respecting TPC's Units

SCHEDULE H

AUTHORIZATIONS - HYDRO

1. Order in Council as required pursuant to the provisions of the Hydro Act.

~~2.~~
Such Additional Borrowing Authorizations required from time to time.

Document comparison by Workshare Compare on May-12-15 1:19:12 PM

Input:	
Document 1 ID	PowerDocs://TDSLAW/325023/20
Description	TDSLAW-#325023-v20-0050406_NCN_Financing_Agreement(withHydro)-Draft#3-062603
Document 2 ID	file://C:/Users/nicolel/AppData/Roaming/OpenText/DM/Temp/TDSLAW-#1787204-v17-2014_Restated_NCN_Financing_Agreement.doc
Description	TDSLAW-#1787204-v17-2014_Restated_NCN_Financing_Agreement
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	243
Deletions	296
Moved from	14
Moved to	14
Style change	0
Format changed	0
Total changes	567

AMENDED AND RESTATED TPC FINANCING AGREEMENT

between

TASKINIGAHP POWER CORPORATION

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD

~~**DATED June 28, 2006**~~

Effective March 31, 2015

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AMENDED AND RESTATED TPC FINANCING AGREEMENT

~~DATED~~Effective the ~~28th~~31st day of ~~June 2006~~March 2015

B E T W E E N:

TASKINIGAHP POWER CORPORATION,

(hereinafter referred to as "TPC")

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter referred to as "Hydro")

The parties agree as follows:

ARTICLE I
INTERPRETATION

1.1 Defined Terms.

In this Agreement, defined terms used herein shall have the following meanings:

~~"**Additional Borrowing Authorizations**" has the meaning specified in Section 8.1(4).~~

~~"**Adjustment Purchase Option Event**" has the meaning specified in Section 6.1(b).~~

~~"**Adjustment Purchase Right**" has the meaning specified in Section 6.1(b).~~

~~"**Adjustment Purchased Units**" has the meaning specified in Section 6.1(b).~~

"**Advances**" means advances made by Hydro under the Equity Credit Facility in this Agreement in Canadian Dollars and **"Advance**" means any one of such Advances. ~~Advances may be designated as an **"Equity Credit Advance"** or a **"Cash Call Credit Advance"**. Each of an Equity Credit Advance and a Cash Call Credit Advance is a **"Type"** of Advance.~~

"**Affiliate**" means with respect to any Person, any other Person directly or indirectly Controlling, Controlled by or under direct or indirect common Control with, such Person.

~~"**Aggregate Capital Contributions**" means for any particular day, the sum of:~~

~~(i) the subscription price paid for the purchase of the Units by the Limited Partners; and~~

~~(ii)~~ "**Aggregate Capital Contributions**" means for any particular day, the sum of: (i) the subscription price paid for the purchase of the Units by the Limited Partners; and (ii) all other capital amounts contributed by the Limited Partners to the Limited Partnership pursuant to the provisions of the Limited Partnership Agreement.

"**Agreement**" means this financing agreement and all schedules and instruments in amendment or confirmation of it; "**hereof**", "**hereto**" and "**hereunder**" and similar expressions refer to this Agreement and not to any particular Article, Section or other subdivision; "**Article**", "**Section**" or other subdivision of this Agreement followed by a number refers to the specified Article, Section or other subdivision of this Agreement.

"**Anniversary Date**" means each anniversary of the Final Closing Date.

~~"**Approved Funds**" means either:~~

~~(i)~~ “**Approved Funds**” means either: (i) funds that TPC will use to repay any principal amount under ~~a~~the Equity Credit Facility, that Hydro has approved pursuant to the Credit Facility Repayment Certification provided by TPC in accordance with Section ~~4.6; or~~4.5; or (ii) funds that TPC will use to make a payment to the Limited Partnership, that Hydro has approved pursuant to the Limited Partnership Payment Certification.

~~(ii) funds that TPC will use to make a payment to the Limited Partnership, that Hydro has approved pursuant to the Limited Partnership Payment Certification provided by TPC in accordance with Section 10.2(11).~~

“**Auditors**” means such firm of chartered accountants as may be selected by the directors of TPC and approved by NCN from time to time to audit TPC, provided that such firm of chartered accountants is qualified to perform audits in Manitoba.

“**Authorization**” means, with respect to any Person, any authorization, order, permit, approval, grant, licence, consent, right, franchise, privilege, certificate, judgment, writ, injunction, award, determination, direction, decree, by-law, rule or regulation of any Governmental Entity having jurisdiction over such Person, whether or not having the force of Law.

“**Banker’s Acceptance Rate**” means the closing rate on any particular day for a one month Canadian Dollar banker’s acceptance, as traced in Bloomberg using the CDORO1 index. Where any Banker’s Acceptance Rate or average of a number of Banker’s Acceptance Rates is used in the calculation of any interest rate or amount due by TPC hereunder (including in the determination of the Canadian Dollar Floating Rate), Hydro shall provide TPC with a print-out of the CDOR01 index screen used to derive such rate or rates.

“**Borrowing**” means a borrowing consisting of one or more Advances.

~~“**Borrowing Notice**” has the meaning specified in Section 4.2(1).~~

“**Business**” means the business of TPC which consists of owning TPC’s Units**,** being a limited partner in the Limited Partnership and making such other investment, administrative and business decisions as may be ancillary thereto and carrying out such functions and fulfilling such obligations as are required or permitted pursuant to the provisions of the PDA.

“**Business Day**” means any day on which Hydro’s head office is open for business at Winnipeg, Manitoba but in any event shall not include a Saturday, Sunday or statutory or civic holiday in Manitoba.

“**Canada**” means the Government of Canada.

“**Canada Yield Price**” means with respect to the repayment of Equity ~~Credit Advances or Cash Call~~ Credit Advances the principal amount that is being repaid plus or minus an amount calculated at 10:00 a.m. (Winnipeg time) on the Business Day preceding the day on which the principal amount is to be repaid which in total if invested on that day would provide a yield to maturity equal to the Government of Canada Yield, plus the Canadian Yield Spread, excluding commissions plus the Canadian Dollar Guarantee Rate ~~and plus the applicable fixed rate adder per annum. The fixed rate adder is one (1%) percent per annum for Equity Credit Facility Advances up to the tenth Anniversary Date and is three (3%) percent per annum thereafter. The fixed rate adder is three (3%) percent for all Cash Call Advances~~. The Canada Yield Price will be determined based on the median of the three investment dealer quotes obtained by Hydro.

“**Canadian Dollar Floating Rate**” means, for any particular day(s) within a given month, the variable rate of interest (expressed as a percentage rate per annum) equal to the Short-Term Canadian Borrowing Cost incurred by Hydro for the month in which such day(s) fall. Provided that if there has been no Short-Term Canadian Borrowing Cost for that month, the variable interest rate (expressed as a percentage rate per annum) shall be based on the average of the daily Banker’s Acceptance Rates for that month plus the average of the daily Canadian Dollar Guarantee Rates for that month plus one (1%) percent per annum.

"**Canadian Dollar Guarantee Rate**" means for any particular day, the closing rate of interest (expressed as a percentage rate per annum) charged on such day by Manitoba to Hydro, as a fee for Manitoba's guarantee of Hydro's Canadian Dollar borrowings.

"**Canadian Dollars**" and "**$**" each mean lawful money of Canada.

~~"**Canadian Ten Year Rate**" means for any particular day, the rate of interest per annum equal to:~~

~~(i) the Ten Year Canada Bond Rate, as at 10:00 a.m. (Winnipeg time), for such day; plus~~

~~(ii) the Canadian Dollar Guarantee Rate, as at 10:00 a.m. (Winnipeg time), for such day and either:~~

~~(A) plus the Canadian Ten Year Spread as at 10:00 a.m. (Winnipeg time) for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread is less than the rate of interest for the Ten Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Ten Year Spread; or~~

~~(B) less the Canadian Ten Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Ten Year Canada Bond Rate used in the calculation of the said Canadian Ten Year Spread was greater than the rate of interest for the Ten Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Ten Year Spread.~~

~~"**Canadian Ten Year Spread**" means at any particular date the difference between the Ten Year Canada Bond Rate in effect on that date and the rate of interest (expressed~~

~~as a percentage rate per annum) for Ten Year Manitoba Canadian Dollar Bonds had Ten Year Manitoba Canadian Dollar Bonds been issued by Manitoba on that day, at 10:00 a.m. (Winnipeg time), including commission costs (with the rate of interest determined by Hydro obtaining three rate quotes for Ten Year Manitoba Canadian Dollar Bonds and using the median of the three rate quotes obtained).~~

~~"**Canadian Thirty Year Rate**" means for any particular day, the rate of interest per annum equal to:~~

~~(i) the Thirty Year Canada Bond Rate, as at 10:00 a.m. (Winnipeg time), for such day; plus~~

~~(ii) the Canadian Dollar Guarantee Rate, as at 10:00 a.m. (Winnipeg time), for such day and either:~~

~~(A) plus the Canadian Thirty Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Thirty Year Canada Bond Rate used in the calculation of the said Canadian Thirty Year Spread is less than the rate of interest for the Thirty Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Thirty Year Spread; or~~

~~(B) less the Canadian Thirty Year Spread, as at 10:00 a.m. (Winnipeg time), for such day, if the Thirty Year Canadian Bond Rate used in the calculation of the said Canadian Thirty Year Spread is greater than the rate of interest for the Thirty Year Manitoba Canadian Dollar Bond used in the calculation of the said Canadian Thirty Year Spread.~~

~~"**Canadian Thirty Year Spread**" means at any particular date the difference between the Thirty Year Canada Bond Rate in effect on that date and the rate of interest (expressed as a percentage rate per annum) for Thirty Year Manitoba Canadian Dollar Bonds had Thirty Year Manitoba Canadian Dollar Bonds been issued by Manitoba on that day, at 10:00 a.m. (Winnipeg time), including commission costs (with the rate of interest being determined by Hydro obtaining three rate quotes for Thirty Year Manitoba Canadian Dollar Bonds and using the median of the three rate quotes obtained).~~

"**Canadian Yield Spread**" means for any particular date, the difference between the Government of Canada Yield determined for that date and the yield to maturity on such day compounded semi-annually which a non-callable Manitoba bond would carry if issued in Canadian Dollars on that day at 10:00 a.m. (Winnipeg time), including commission costs, at 100% of its principal amount on such day with the term to maturity equal to the remaining term to Maturity for the Equity Credit Advances~~ or Cash Call Credit Advances, as applicable,~~ that are being repaid. The Canadian Yield Spread will be determined by Hydro obtaining three rate quotes from investment dealers and using the median of the three rate quotes obtained.

"**Capital Stock**" means, with respect to any Person, any and all shares, interests, participation or equivalent interest in (however designated) the equity (including, without limitation, common shares, preferred shares, trust units and partnership interests) of such Person and any rights, warrants or options to subscribe for or acquire an equity interest in such Person.

~~"**Cash Call Credit Advance**" means an Advance denominated in Canadian Dollars under the Cash Call Credit Facility which bears interest based on the Canadian Ten Year Rate, as determined in accordance with this Agreement.~~

~~"**Cash Call Credit Facility**" means the non-revolving credit facility to be made available to TPC by Hydro in the maximum amount of the Cash Call Credit Facility Commitment and in accordance with the terms hereof.~~

~~"**Cash Call Credit Facility Commitment**" means the aggregate principal amount of TPC's Operating Cash Call Requirements.~~

~~"**Cash Call Over-Drawn Amount"** has the meaning specified in Section 3.6(1).~~

~~"**Cash Unit Portion**" has the meaning specified in Section 3.5(2).~~

"**Change of Control**" means any change which results in NCN no longer directly owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of the bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC, as bare trustee for NCN, commits to vote such Capital Stock in accordance with the direction of Chief and Council of NCN), and for greater certainty the NCN Deed of Assignment does not effect a Change of Control.

"**Chief**" has the meaning ascribed thereto in the PDA.

"**Chief and Council**" has the meaning ascribed thereto in the PDA.

"**Claim**" means any claim of any nature whatsoever, including any demand, dispute, liability, obligation, debt, action, cause of action, suit, proceeding, litigation, arbitration, judgment, order, award, assessment and reassessment.

"**Collateral**" means TPC's Units and the Distributions thereon, in respect of which Hydro has or will have or is intended to have a Lien pursuant to the Security Documents.

~~"**Construction Period**" means the approximately six (6) year period during which the Wuskwatim Project is being constructed, which for the purposes of this Agreement will be the period commencing on the Initial Closing Date and ending on the Final Closing Date.~~

"**Corporate Distributions**" means, in respect of any Person, whether or not a corporation, any form of distribution of its profits, including in each case any:

(i) declaration or payment of any dividend on its Capital Stock; and

(ii) payment to purchase, redeem, retire or acquire or reduce the stated capital of any of its Capital Stock, or any option, warrant or other right to acquire any such Capital Stock, or apply or set apart any of its Property therefore.

"**Councillor**" has the meaning ascribed thereto in the PDA.

~~"**Credit Facilities**" means the Equity Credit Facility and the Cash Call Credit Facility, and a "**Credit Facility**" means any one of the Equity Credit Facility or the Cash Call Credit Facility, as the context requires.~~

~~"**Credit Facility Commitment**" means one of the Equity Credit Facility Commitment, or the Cash Call Credit Facility Commitment, as the context requires and "**Credit Facility Commitments**" means both of them.~~

"**Credit Facility Repayment Certification**" has the meaning specified in Section ~~4.6.~~4.5.

"**Cure Period**" has the meaning specified in Section 12.1(c).

"**Date of the PDA**" has the meaning ascribed thereto in the PDA.

"**Debt**" of any Person means, without duplication:

~~(a)~~ (i) all obligations of such Person for borrowed money or Advances and all obligations of such Person evidenced by bonds, debentures, notes or similar instruments;

~~(b)~~ (ii) all obligations of such Person, contingent or otherwise, relative to the face amount of all letters of credit, whether or not drawn, and banker's acceptances issued for the account of such Person; and

~~(c)~~ (iii) all other items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of such Person as of the date at which Debt is to be determined (excluding trade payables incurred in the ordinary course of business).

"**Distributions**" means distributions of cash of the Limited Partnership to TPC and the return of any part of the Aggregate Capital Contributions by the Limited Partnership to TPC.

"**Dividends**" has the meaning ascribed thereto in the NCN Deed of Assignment.

"**Dividend Credit Facility**" has the meaning ascribed thereto in the NCN Financing Agreement.

"**Equity Credit Advance**" means an Advance denominated in Canadian Dollars under the Equity Credit Facility ~~which bears interest based on the Canadian Dollar Floating Rate or the Canadian Thirty Year Rate, as determined in accordance with this Agreement~~.

"**Equity Credit Facility**" means the non-revolving credit facility to be made available to TPC by Hydro in the maximum amount of the Equity Credit Facility Commitment and in accordance with the terms ~~hereof.~~ of this Agreement.

~~"**Equity Credit Facility Adjustment Conditions**" has the meaning specified in Section 2.6(4).~~

"**Equity Credit Facility Commitment**" means the aggregate principal amount of ~~TPC's Construction Cash Call Requirements.~~

~~"**Equity Credit Facility Final Closing Conditions**" has the meaning specified in Section 2.6(3).~~ ~~"**Equity Credit Over-Drawn Amount**" has the meaning specified in Section 2.6(1).~~ninety-two million three hundred sixty-two thousand ($92,362,000) dollars.

"**Event of Default**" has the meaning specified in Section 12.1.

"**Final Closing**" and "**Final Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

~~**Final Closing Date Interest Obligations**" means all accrued and unpaid interest under this Agreement in respect of the Equity Credit Facility, as at the Final Closing Date.~~

~~"**Final Closing Date Principal Obligations**" means the Total Outstandings under this Agreement and Loan Documents in respect of the Equity Credit Facility, and all unpaid costs and other amounts due and owing to Hydro under or in respect of the Equity Credit Facility, as at the Final Closing Date, but not including accrued and unpaid interest.~~

~~"**Final Closing Purchase Option Event**" has the meaning specified in Section 6.1(a).~~

~~"**Final Closing Purchase Right**" has the meaning specified in Section 6.1(a).~~

~~"**Final Closing Purchased Units**" has the meaning specified in Section 6.1(a).~~

~~"**Final Closing Sale Right**" has the meaning specified in Section 5.1(a).~~

~~"**Final Closing Sale Units**" has the meaning specified in Section 5.1(a).~~

~~"**Final Closing Sale Conditions**" means:~~

~~(i) NCN owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the~~

~~unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of Chief and Council of NCN);~~

~~(ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Final Closing Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing, and TPC has the full right to sell and transfer the Final Closing Sale Units to Hydro;~~

~~(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Final Closing Sale Units other than Hydro;~~

~~(iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment or right for the purchase of any of the Capital Stock of TPC; and~~

"**Final Investment Closing**" means 10:00 a.m. on the Final Investment Date.

~~(v) the consummation of the transactions contemplated by the exercise of the Final Closing Sale Right will not result in the creation or imposition of any Lien on the Final Closing Sale Units (other than such Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing).~~

"Final Investment Date" means January 1, 2015.

~~"**Financial Quarter**" means, in relation to TPC, each successive period of three consecutive months, the first such period beginning on the first day of the first month of TPC's Financial Year.~~

"**Financial Year**" means, in relation to TPC, the financial year of TPC as determined by the board of directors of TPC.

"**Future Material Agreement**" has the meaning specified in Section 10.1(13).

"**GAAP**" means, at any time, generally accepted accounting principles in Canada as recommended in the Handbook of the Canadian Institute of Chartered Accountants, or any successor Person at such time.

"**General Partner**" means 5022649 Manitoba Ltd., in its capacity as the general partner of the Limited Partnership, pursuant to the terms of the Limited Partnership Agreement.

"**Government Funds**" means any funds provided or advanced to NCN or TPC by Canada or Manitoba, or by any crown corporation, agency, department or instrumentality of Canada or Manitoba on the condition or requirement that such funds are to be used for investment through or by TPC in the Limited Partnership, and which TPC:

(i) uses to repay any principal amount outstanding under ~~a~~the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which, for greater certainty, does not include any other amount paid to Hydro under the Equity Credit ~~Facilities~~Facility); or

(ii) uses to make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification;

and, for greater certainty, does not include any grants, loans or funds provided or advanced by any of the said parties to NCN or TPC without any condition or requirement that such grants, loans or funds are to be used for investment through or by TPC in the Limited Partnership, in which event the said grants, loans or funds will, after TPC's repayment of an Advance or payment to the Limited Partnership, as applicable, form part of TPC's Own Funds hereunder, without further qualification as "Government Funds".

"**Government of Canada Yield**" means for any particular date, the yield to maturity on such date compounded semi-annually which a non-callable Government of Canada bond would carry if issued, in Canadian Dollars, at 100% of its principal amount on such day at 10:00 a.m. (Winnipeg time) with a term to maturity equal to the remaining term to Maturity for the Equity Credit Advance~~ or Cash Call Credit Advance, as applicable,~~ that is being repaid. The Government of Canada Yield will be the yield determined by Hydro obtaining three rate quotes from investment dealers and using the median of the three rate quotes obtained.

"**Governmental Entity**" means any:

(i) federal, provincial, state, regional, municipal, local or other government, governmental or public department, central bank, court, commission, board, bureau, agency or instrumentality, domestic or foreign;

(ii) any agent, commission, board, or authority of any of the foregoing; or

(iii) any body exercising any regulatory, expropriation or taxing authority under or for the account of any of the foregoing except not including Hydro for the purposes of this Agreement.

"**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by the Hydro Act.

"**Hydro Act**" means *The Manitoba Hydro Act*, R.S.M. 1987, c. H190, as amended from time to time.

"**Hydro's Account**" means such account or accounts maintained by Hydro at the Royal Bank of Canada, as Hydro from time to time notifies TPC for the purposes of this Agreement.

"**Hydro Liens**" means:

(i) Liens in favour of Hydro created by the Security Documents hereunder or by the Security Documents (as defined in the NCN Financing Agreement); and

(ii) Liens in favour of Hydro created by the Revenue Advance Consolidation Agreement and the security agreements provided by TPC to Hydro pursuant to that agreement.

"**Initial Closing**" **and "Initial Closing Date**" shall have the respective meanings ascribed thereto in the PDA.

~~"**Initial Closing Conditions**" has the meaning ascribed thereto in the PDA.~~

"**Initial Limited Partnership Agreement**" means the limited partnership agreement entered into between the General Partner, in its capacity as general partner, and Hydro, as limited partner, dated the 9th day of December, 2004.

"Initial TPC Financing Agreement" means the TPC Financing Agreement entered into between TPC and Hydro dated June 28, 2006 which agreement remained in effect to and including March 31, 2015.

"**Laws**" means all statutes, codes, ordinances, decrees, rules, regulations, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, decisions, rulings or awards, or any provisions of the foregoing, including general principles of common and civil law and equity, binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one of such Laws.

"**Lien**" means, with respect to any Property, any charge, mortgage, pledge, hypothecation, security interest, lien, conditional sale (or other title retention agreement or lease in the nature thereof), lease, servitude, assignment, adverse claim, defect of title, restriction, trust, or other encumbrance of any kind in respect of such Property, whether or not filed, recorded or otherwise perfected under applicable Laws.

"**Limited Partner**" means one of Hydro or TPC, as the context requires, in its capacity as a limited partner of the Limited Partnership, and "**Limited Partners**" means both of Hydro and TPC, in their respective capacities as limited partners of the Limited Partnership.

"**Limited Partnership**" means the Wuskwatim Power Limited Partnership created pursuant to the Initial Limited Partnership Agreement~~, as amended~~ and ~~restated by~~continued pursuant to the Limited Partnership Agreement, for the purposes of owning and directly or indirectly planning, designing, constructing, operating and maintaining the Wuskwatim Project.

"**Limited Partnership Account**" means the Canadian Dollar account maintained by the Limited Partnership at Royal Bank of Canada, the particulars of which shall have been notified by the Limited Partnership to Hydro.

"**Limited Partnership Agreement**" means the ~~limited partnership agreement~~Third Amended and Restated Limited Partnership Agreement amending and restating the ~~Initial~~second Limited Partnership Agreement, dated even date herewith between the General Partner, in its capacity as general partner, and Hydro and TPC, in their respective capacities as limited partners.

"**Limited Partnership Payment Certification**" has the meaning specified in Section 10.2(11).

"**Loan Documents**" means this Agreement, the Security Documents, and all other agreements, certificates and instruments delivered or given pursuant to or in connection with this Agreement; and "**Loan Document**" means any one of such Loan Documents.

"**Loss**" means any loss whatsoever, whether direct or indirect, including expenses, costs, damages, judgments, penalties, fines, charges, claims, demands, liabilities, debts, interest, any and all legal fees and disbursements on a solicitor and his own client basis.

"**Manitoba**" means the Government of Manitoba.

"**Market Make-whole Payment**" has the meaning specified in Section ~~13.9.~~13.11.

"**Material Adverse Business Effect**" means a material adverse effect (or a series of adverse effects, none of which is material in or of itself but which cumulatively results in a material adverse effect) on:

(i) the ability of TPC to perform any of its material obligations under the Loan Documents; or

(ii) the ability of Hydro to enforce any of the material obligations of TPC under the Loan Documents, where Hydro, acting reasonably, has determined that its ability to enforce the said material obligations cannot be cured by Hydro within a reasonable period of time or without Hydro being materially adversely affected, notwithstanding that TPC has provided its written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said material obligations of TPC under the Loan Documents.

"**Material Agreements**" has the meaning specified in Section 9.1(11).

"**Maturity Date**" means the fiftieth Anniversary Date.

"**Maturity Sale Conditions**" means:

(i) NCN owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of Chief and Council of NCN);

(ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Maturity Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing, and TPC has the full right to sell and transfer the Maturity Sale Units to Hydro;

(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Maturity Sale Units other than Hydro;

(iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment or right for the purchase of any of the Capital Stock of TPC; and

(v) the consummation of the transactions contemplated by the exercise of the Maturity Sale Right will not result in the creation or imposition of any Lien on the Maturity Sale Units (other than such other Liens as Hydro, on the Maturity Date, may in its unfettered discretion accept in writing).

"**Maturity Sale Right**" has the meaning specified in Section 5.1(~~d~~b).

"**Maturity Sale Units**" has the meaning specified in Section 5.1(~~d~~b).

"**NCN**" means the Nisichawayasihk Cree Nation, formerly known as the Nelson House First Nation.

"**NCN Business**" has the meaning ascribed thereto in the PDA.

"**NCN Deed of Assignment**" has the meaning ascribed thereto in the PDA.

"**NCN Financing Agreement**" means ~~a~~ the amended and restated financing agreement dated ~~even date herewith~~April 16, 2015 between NCN, TPC, and Hydro.

~~"**Non-Completion Date**" has the meaning specified in Section 5.1(b).~~

~~"**Non-Completion Purchase Option Event**" shall have the meaning specified in Section 6.1(c).~~

~~"**Non-Completion Purchase Right**" shall have the meaning specified in Section 6.1(c).~~

~~"**Non-Completion Purchased Units**" shall have the meaning specified in Section 6.1(c).~~

~~"**Non-Completion Sale Conditions**" means:~~

~~(i) NCN owing beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC, as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of Chief and Council of NCN);~~

~~(ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Non-Completion Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion, accept in writing, and TPC has the full right to sell and transfer the Non-Completion Sale Units to Hydro;~~

~~(iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC the Non-Completion Sale Units other than Hydro;~~

~~(iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option,~~

~~understanding, commitment or right for the purchase of any of the Capital Stock of TPC; and~~

~~(v) the consummation of the transactions contemplated by the exercise of the Non-Completion Sale Right will not result in the creation or imposition of any Lien on the Non-Completion Sale Units (other than such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion, accept in writing).~~

~~"**Non-Completion Sale Right**" shall have the meaning specified in Section 5.1(b).~~

~~"**Non-Completion Sale Units**" shall have the meaning specified in Section 5.1(b).~~

"**Notice**" means any notice, citation, directive, request for information, writ, summons, and statement of claim or other communication from any Person.

~~"**Notice of Purchase**" has the meaning specified in Section 6.3.~~

"**Notice of Sale**" has the meaning specified in Section ~~5.3.~~5.5.

"**Obligations**" has the meaning specified in Section 11.1.

"**PDA**" means the Project Development Agreement dated June 26, 2006 made between NCN, Hydro, TPC, the General Partner and the Limited Partnership~~.~~ as supplemented and amended by PDA Supplement No. 1 dated March 15, 2011 and PDA Supplement No. 2 dated April 16, 2015.

"**Permitted Liens**" means, with respect to any Person, any one or more of the following:

(i) Liens for Taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such taxes, assessments and charges;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(ii) Liens resulting from any judgment rendered or Claim filed against such Person which such Person shall be contesting in good faith by proper legal proceedings if, in Hydro's opinion:

(A) adequate security has been provided to ensure the payment of such judgment or Claim;

(B) adequate reserves with respect thereto are maintained on the books of such Person, in accordance with GAAP; and

(C) in each case, such Liens will not materially interfere with use of such Property by such Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(iii) undetermined Liens arising in the ordinary course of business which have not at such time been filed pursuant to Law against such Person or which relate to obligations not due or delinquent;

(iv) Liens arising in the ordinary course of business which are not registered against title to the Collateral and are not overdue for a period of more than thirty (30) days or which are being contested at the time by the Person in good faith by proper legal proceedings if, in Hydro's opinion, (i) adequate security has been provided to ensure payment of such Liens; (ii) adequate reserves with respect thereto are maintained on the consolidated books of such Person in accordance with GAAP; and (iii) in each case, such Liens will not materially interfere with use of such Property by the Person or involve any immediate danger of the sale, forfeiture or loss of such Property;

(v) any Lien, payment of which has been provided for by the depositing with Hydro of an amount in cash, or the obtaining of a surety bond satisfactory to Hydro, in its absolute discretion, sufficient in either case to pay or discharge such Lien and which deposit or bond Hydro is authorized to use or draw upon for that purpose;

(vi) Liens securing Purchase Money Debt provided that: (i) such Liens shall extend only to the specific Property of the Person acquired with the proceeds of such Purchase Money Debt (and not any portion of the Collateral) and (ii) recourse in respect of such Liens shall be limited to such specific Property;

(vii) the Hydro Liens; or

(viii) any other Lien approved in writing in advance by Hydro, in its unfettered discretion.

“**Person**” means an individual, partnership, corporation, trust, unincorporated association, syndicate, joint venture, Band within the meaning of the *Indian Act* (Canada) or other entity or Governmental Entity, and pronouns have a similarly extended meaning.

“**Property**” means, with respect to any Person, any interest of such Person in any land or property or asset of every kind, wherever situate, whether now owned or hereafter acquired, whether real or immovable, personal, movable or mixed, tangible or corporeal, intangible or incorporeal, including capital stock in any other Person.

“**Purchase Money Debt**” means, with respect to any Person, all obligations of such Person incurred to finance the acquisition of Property.

~~“**Purchased Units**” means the Final Closing Purchased Units, the Adjustment Purchased Units or the Non-Completion Purchased Units, as the context requires.~~

“**Receiver**” means a receiver, receiver and manager or other person having similar powers or authority appointed by Hydro or by a court at the instance of Hydro in respect of the Collateral or any part thereof.

“**Repayment Notice**” has the meaning specified in Section ~~4.6.~~4.5.

“**Revenue Advance Consolidation Agreement**” has the meaning ascribed thereto in the PDA.

“**Sale**” means a transaction of purchase and sale of all or a portion of TPC’s Units pursuant to Article V~~ or Article VI~~.

"**Sale Certificates**" has the meaning specified in Section 7.1(2)(a).

"**Sale Closing Date**" has the meaning specified in Section 7.1(1)(a).

"**Sale Units**" means the ~~Final Closing Sale Units, the Non-Completion Sale Units~~, the Twenty-Fifth Anniversary Sale Units, the Maturity Sale Units or the Term Sale Units, as the context requires.

"**Security Documents**" means those agreements and other documents in favour of Hydro described in Schedule G, in form and substance satisfactory to Hydro, acting reasonably, as such documents may be amended or restated from time to time, as security for all or any portion of the Obligations.

"**Short-Term Canadian Borrowing Cost**" means, for any month, Hydro's actual weighted average borrowing cost (which, it is acknowledged, includes the Canadian Dollar Guarantee Rate) expressed as a percentage rate per annum for all of Hydro's Canadian Dollar borrowings outstanding during that month which have a term expiring, or are due to be paid, within three hundred and sixty-four (364) days in length of the date that each such borrowing was first incurred by Hydro. Hydro's "actual weighted average borrowing cost" shall be calculated on the basis of the actual amount of interest that has accrued during that month divided by the "weighted principal amount" of all borrowing(s) which accrued interest during that month. The "weighted principal amount" for each borrowing is equal to the principal amount of each borrowing multiplied by the number of days the borrowing was outstanding during the month divided by 365.

~~"**Substantial Construction Start**" has the meaning ascribed thereto in the PDA.~~

"**TPC**" means Taskinigahp Power Corporation, a corporation that is wholly owned by NCN beneficially, and by the Chief or a Councillor of NCN, as registered owner as bare trustee for NCN.

~~"**TPC's Cash Subscription Payment**" means the actual cash amount using Approved Funds paid by TPC on the Initial Closing Date to subscribe for Units in the Limited Partnership.~~

"**TPC's Cash Units**" means:

(i) on the Final ~~Closing Date, [but shall be determined for all provisions of this Agreement after any mandatory payments required by Section 2.6(3) have been made and, except for the purposes of Sections 5.1(a), 5.2(1), 6.1(a), 6.2(1) and 6.2(2) only, after any Sale of TPC's Units pursuant to Article V or Article VI has closed in accordance with Article VII (for such of Sections 5.1(a), 5.2(1), 6.1(a), 6.2(1), and 6.2(2), as may become applicable, shall be determined before any Sale of TPC's Units pursuant to Article V or Article VI has closed in accordance with Article VII)]~~Investment Date that number of TPC's Units equal to (A) divided by (B) where (A) equals the number of TPC's Units on the Final ~~Closing~~ Investment Date multiplied by TPC's Invested Cash as of that date; and (B) equals the sum of: (i) the aggregate of the amount of Equity Credit Advances which remain outstanding on that date; and (ii) TPC's Invested Cash as of that date; and

~~(ii)~~ (ii) on any particular day after the Final ~~Closing~~ Investment Date (the "**Measurement Date**") until the date that the Equity Credit Facility has been paid ~~out~~ in full, that number of TPC's Units equal to (A) divided by (B) where (A) is the product of: (i) the number of TPC's Cash Units on the Final ~~Closing~~ Investment Date, multiplied by (ii) the number of TPC's Units on the Measurement Date; and (B) equals the number of TPC's Units on the Final ~~Closing~~ Investment Date; and

~~(iii) for~~For greater certainty, on the date when the Equity Credit

Facility has been paid out in full, all of TPC's Units shall be deemed to be TPC's Cash Units.

~~"**TPC's Construction Cash Call Requirements**" and "**TPC's Construction Cash Call Requirement**" shall have their respective meanings ascribed thereto in Section 2.4.~~

"**TPC's Invested Cash**" means on any particular day, the sum of all amounts invested by TPC in the Limited Partnership using Approved Funds. For greater certainty:

(i) this does not include the proceeds of Equity Credit Advances~~ or Cash Call Credit Advances~~;

(ii) this does not include any amount for interest, costs, expenses or indemnity reimbursed or paid to Hydro hereunder; and

(iii) this does include all of TPC's Own Funds (which includes Government Funds) and all of TPC's Third Party Funds used by TPC either:

(A) to repay any principal amount outstanding under a Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification; or

(B) to make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification (including, without limitation, TPC's Cash Subscription Payment);

all of which amounts shall, after approval has been granted by Hydro, constitute Approved Funds.

"**TPC's Loan Units**" means, on any particular day, all of TPC's Units on that day that are not TPC's Cash Units.

~~"**TPC's Operating Cash Call Requirements**" and "**TPC's Operating Cash Call Requirement**" shall have their respective meanings ascribed thereto in Section 3.4.~~

"**TPC's Own Funds**" means any funds that TPC will use to:

(i) repay any principal amount outstanding under ~~a~~the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which, for greater certainty, does not include any other amount paid to Hydro under the Equity Credit ~~Facilities~~Facility);

(ii) make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification; or

(iii) make TPC's Cash Subscription Payment;

provided that the said funds have not been obtained by TPC (whether directly or indirectly through NCN, an NCN Business or the Taskinigahp Trust) from any arm's length Person, in any material way due to or as a result of:

(A) TPC being the owner of one or more Units; or

(B) TPC, NCN or Taskinigahp Trust providing or agreeing to provide, directly or indirectly, a Lien in favour of any other Person on, or by TPC, NCN or the Taskinigahp Trust conferring an ownership or proprietary interest or any kind upon any other Person, in any

Property of TPC or the Property of Taskinigahp Trust (provided that this is not intended to prohibit or restrict the beneficial interest of the beneficiaries of the Taskinigahp Trust under the Trust Indenture constituting the Taskinigahp Trust), the Capital Stock of TPC, TPC's Units or any Distributions on the TPC's Units, or on any Corporate Distributions of TPC, including assignments or orders to pay.

For greater certainty, the mere investment of funds by NCN, an NCN Business or the Taskinigahp Trust in TPC for use by TPC in either repaying any principal amount under ~~a~~the Equity Credit Facility or making a payment to the Limited Partnership in the manner referenced above shall not preclude such funds from constituting TPC's Own Funds, and any funds so invested by NCN, an NCN Business or the Taskinigahp Trust in TPC shall be considered in all respects to be TPC's Own Funds for the purposes of this Agreement if Hydro determines that the funds otherwise fall within the definition of TPC's Own Funds in accordance with the provisions of this Agreement (and, for this purpose, Hydro shall be entitled to look to the source of the funds to NCN, the NCN Business or the Taskinigahp Trust). Government Funds (once approved as such by Hydro pursuant to the approval processed hereunder) and funds obtained by TPC from Distributions on TPC's Units or from earnings on the investment of Distributions on TPC's Units which are voluntarily used to repay any principal amount (but no other amount) under ~~a~~the Equity Credit Facility or which are invested in the Limited Partnership pursuant to a Credit Facility Repayment Certification or a Limited Partnership Payment Certification respectively shall be deemed for the purposes of this Agreement to be TPC's Own Funds (but, for greater certainty, amounts paid to Hydro pursuant to the irrevocable assignment and direction of Distributions on TPC's Units under the Security Documents shall not count or be included as part of TPC's Own Funds).

"**TPC's Third Party Funds**" means any funds that TPC will use to either:

(i) repay any principal amount under ~~a~~the Equity Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification (which for greater certainty does not include any other amount paid to Hydro under the Equity Credit ~~Facilities~~Facility); or

(ii) make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification;

which are not TPC's Own Funds. For greater certainty:

(A) the mere assignment of Dividends by NCN to the Taskinigahp Trust pursuant to the NCN Deed of Assignment shall not be deemed to constitute any of TPC's funds as being TPC's Third Party Funds hereunder;

(B) merely because funds have been obtained by NCN from a third party, whether by loan, grant, subsidy or otherwise shall not be sufficient for such funds to be deemed to be TPC's Third Party Funds; and

(C) none of NCN, any NCN Business or the Taskinigahp Trust shall be deemed to be a third party for the purposes of determining what funds are TPC's Own Funds and what funds are TPC's Third Party Funds, provided however, that where the source of any funds is any of NCN, an NCN Business or the Taskinigahp Trust, Hydro is entitled to look beyond such party to determine the ultimate source of such funds in applying the provisions hereof.

"**TPC's Units**" means, at any time, the Units owned by TPC.

"Taskinigahp Trust" has the meaning ascribed thereto in the PDA.

"**Taxes**" means all taxes imposed by any Governmental Entity, including real property, personal property, goods and services, sales, transfer, purchase, stumpage, registration, capital, excise, import duties, payroll, unemployment, disability, employee's income withholding, social security or withholding.

"**Ten Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of ten years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian Dollar non-callable Government of Canada reference bonds with a ten year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the ten year term, and using the median rate of the three rate quotes obtained).

"**Ten Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba, at 100% of the principal amount for a term of ten years.

"**Term Sale Conditions**" means:

~~(i)~~ (i) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Term Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing;

~~(ii)~~ (ii) TPC has the full right to sell and transfer the Term Sale Units to Hydro;

~~(iii)~~ (iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Term Sale Units other than Hydro; and

~~(iv)~~ (iv) the consummation of the transactions contemplated by the exercise of the Term Sale Right will not result in the creation or imposition of any Lien on the Term Sale Units (other than such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing).

"Term Sale Right" has the meaning specified in Section 5.1(~~e~~c).

"**Term Sale Units**" has the meaning specified in Section 5.1(~~e~~c).

"**Thirty Year Canada Bond Rate**" means, at any particular date, that rate of interest (expressed as a percentage rate per annum) which a non-callable Government of Canada bond denominated in Canadian Dollars would carry if issued on such date at 10:00 a.m. (Winnipeg time) by Canada at 100% of its principal amount for a term of thirty years (with the rate of interest being determined by Hydro obtaining three rate quotes for the yield on that date of publicly traded Canadian Dollar non-callable Government of Canada reference bonds with a thirty year term, as adjusted by the financial institutions that have provided the three rate quotes to reflect the assumed issue date and the thirty year term, and using the median rate of the three rate quotes obtained).

"**Thirty Year Manitoba Canadian Dollar Bonds**" means a non-callable Province of Manitoba bond denominated in Canadian Dollars issued by Manitoba at 100% of the principal amount for a term of thirty years.

~~"**Time of Adjustment**" means 10:00 o'clock in the forenoon, Winnipeg time, on the first Anniversary Date.~~

~~"**Time of Final Closing**" has the meaning ascribed thereto in the PDA.~~

"**Total Outstandings**" means~~, at any time:~~

~~(a) with respect to the Equity Credit Facility,~~ the aggregate amount in Canadian Dollars of all outstanding Advances ~~thereunder at such time;~~

~~(b) with respect to the Cash Call Credit Facility, the aggregate amount in Canadian Dollars of all outstanding Advances thereunder at such time; and~~

~~(c) with respect to the Credit Facilities, the aggregate of the Total Outstandings under the Credit Facilities;~~at any time under the Equity Credit Facility but~~, for greater certainty,~~ does not include any interest, costs, expenses or indemnity claim arising under ~~any such~~the Equity Credit ~~Facilities~~Facility.

"**Twenty-Fifth Anniversary Sale Conditions**" means:

~~(i)~~ (i) NCN owning beneficially on a fully diluted basis 100% of the Capital Stock of TPC free and clear of all Liens except Permitted Liens (and the unfettered right to direct the exercise of voting rights in respect thereto in accordance with the provisions of a bare trustee declaration pursuant to which the Chief or a Councillor of NCN, as the registered owner of 100% of the Capital Stock of TPC as bare trustee for NCN, commits to vote such Capital Stock in accordance with the directions of the Chief and Council of NCN);

~~(ii)~~ (ii) TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Twenty-Fifth Anniversary Sale Units free and clear of all Liens except the Permitted Liens and such other Liens as Hydro, on the Sale Closing Date, may in its unfettered discretion accept in writing, and TPC has the full right to sell and transfer the Twenty-Fifth Anniversary Sale Units to Hydro;

~~(iii)~~ (iii) no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Twenty-Fifth Anniversary Sale Units other than Hydro;

~~(iv)~~ (iv) no Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment or right for purchase of any of the Capital Stock of TPC; and

~~(v)~~ (v) the consummation of the transactions contemplated by the exercise of the Twenty-Fifth Anniversary Sale Right will not result in the creation or imposition of any Lien on the Twenty-Fifth Anniversary Sale Units (other than such other Liens as Hydro, on the Sale Closing Date, may accept in writing in its unfettered discretion).

"**Twenty-Fifth Anniversary Sale Right**" has the meaning specified in Section 5.1(~~e~~a).

"**Twenty-Fifth Anniversary Sale Units"** has the meaning specified in Section 5.1(~~e~~a).

"**Unit**" means one of the units in the Limited Partnership issued to and subscribed for by a Limited Partner pursuant to the Limited Partnership Agreement, and "**Units**" means all of the issued Units in the Limited Partnership.

"**Wuskwatim Project**" has the meaning ascribed thereto in the PDA.

1.2 ~~1.2~~ Interpretation.

This Agreement shall be interpreted in accordance with the following:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) headings are inserted for convenience only and shall not affect the interpretation of this Agreement, any other Loan Documents or any provisions hereof or thereof;

(c) references to dollars, unless otherwise specifically indicated, shall be references to Canadian Dollars;

(d) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(e) the expressions “the aggregate”, “the total”, “the sum” and expressions of similar meaning shall mean “the aggregate (or total or sum) without duplication”;

(f) in the computation of periods of time, unless otherwise expressly provided, the word “from” means “from and including” and the words “to” and “until” mean “to but excluding”;

(g) accounting terms not specifically defined shall be construed in accordance with GAAP. Except as otherwise mandated by changes in GAAP from time to time, the financial statements required to be delivered pursuant to this Agreement shall be prepared, and all calculations made for the purposes of this Agreement shall be made, unless otherwise provided for herein, by the application of GAAP applied on a basis consistent with the most recent audited financial statements of TPC, previously delivered to Hydro; and

(h) for the purposes of this Agreement, a Person (the “**first Person**”) shall be deemed to be “**Controlled**” by another Person or Persons if the Capital Stock of the first Person directly or indirectly held by or for the benefit of the other Person or Persons, acting in concert, other than by way of security only, is either:

(i) more than 50% of the Capital Stock of the first Person outstanding at the time of such determination; or

(ii) sufficient to permit the other Person or Persons to replace or elect the majority of the board of directors of the first Person;

and “**Control**” and “**Controlling**” shall have corresponding meanings.

1.3 Interpretation of any other Loan Documents.

The provisions of Article 1.2 shall apply to the interpretation of all of the other Loan Documents unless specifically otherwise indicated therein.

1.4 Severability.

If any provision of this Agreement or any other Loan Document is, or becomes, illegal, invalid or unenforceable, such provision shall be severed from this Agreement or such other Loan Document and be ineffective to the extent of such illegality, invalidity or unenforceability. The remaining provisions hereof or thereof shall be unaffected by such provision and shall continue to be valid and enforceable.

1.5 Entire Agreement.

This Agreement supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the parties relating to the subject matter hereof and entered into prior to the date of this Agreement.

1.6 ~~1.6~~ Waiver.

No failure on the part of Hydro to exercise, and no delay in exercising, any right under this Agreement or any other Loan Document shall operate as a waiver of such right; nor shall any single or partial exercise of any right under this Agreement or any other Loan Document preclude any other or further exercise thereof or the exercise of any other right, nor shall any waiver of one provision be deemed to constitute a waiver of any other provision (whether or not similar). No notice to or demand on TPC in any case shall entitle it to any notice or demand in similar or other circumstances, unless such notice or demand is required under the terms of this Agreement or the applicable Loan Document. No waiver of any of the provisions of this Agreement or any other Loan Document shall be effective unless it is in writing duly executed by the waiving party.

1.7 ~~1.7~~ Governing Law.

This Agreement and each other Loan Document, shall be governed by, and interpreted in accordance with, the Laws of Manitoba and the Laws of Canada applicable therein.

1.8 Incorporation of Schedules.

The following schedules attached shall, for all purposes hereof, be incorporated in and form an integral part of this Agreement:

Schedule A	Repayment Notice
Schedule B	~~Borrowing~~Intentionally ~~Notice~~Deleted
Schedule C	Issued and Outstanding Capital Stock and Debt
Schedule D	Material Agreements
Schedule E	Liabilities
Schedule F	Address for Notice
Schedule G	List of Security Documents
Schedule H	Authorizations - Hydro

It is acknowledged by Hydro that Schedules C to E (both inclusive) ~~shall be~~ were delivered by TPC to Hydro on or before the Initial Closing Date for attachment ~~hereto, and upon the delivery and attachment, the~~to the Initial TPC Financing Agreement, which said Schedules shall be deemed to form part of this Agreement.

1.9 ~~1.9~~ Conflicts.

If a conflict or inconsistency exists between a provision of this Agreement and a provision of any of the other Loan Documents or any part thereof, then the provisions of this Agreement shall prevail. Notwithstanding the foregoing, if there is any right or remedy of Hydro set out in any of the other Loan Documents or any part thereof which is not set out or provided for in this Agreement, such additional right or remedy shall not constitute a conflict or inconsistency.

ARTICLE II
EQUITY CREDIT FACILITY

2.1 Equity Credit Facility.

~~Hydro agrees, on the terms and conditions of this Agreement, to make available to TPC the Equity Credit Facility by making such Advances to TPC as may be requested by TPC hereunder at any time and from time to time prior to the first Anniversary Date in accordance with this Agreement.~~

~~**2.2 Credit Facility Commitment and Facility Limit.**~~

~~(1) Hydro shall not be obliged to make any Equity Credit Advance or Equity Credit Advances which would cause the Total Outstandings under the Equity Credit Facility to be greater than the Equity Credit Facility Commitment, provided that, if no Event of Default has otherwise occurred that remains outstanding and uncured at that time, Hydro shall advance, in accordance with the provisions of this Agreement, as an Equity Credit Advance to TPC upon request, the lesser of the amount requested by TPC and the amount hereunder which would, when~~

~~advanced, cause the Total Outstandings with respect to the Equity Credit Facility to equal, but not exceed, the Equity Credit Facility Commitment.~~

~~(2) The Equity Credit Facility may be drawn upon by TPC at any time on or after the Initial Closing Date until immediately prior to the first Anniversary Date subject to the terms and conditions of this Agreement.~~Hydro made, on the terms and conditions of the Initial Agreement, ninety-two million three hundred sixty-two thousand ($92,362,000) dollars in advances to TPC pursuant to the Equity Credit Facility to October 14, 2014, exclusive of accrued interest. The terms of this Agreement shall govern the financing and repayment of the Equity Credit Facility and accrued interest as of the Final Investment Date.

2.2 Non-Revolving Facility

~~(3)~~ The Equity Credit Facility is a non-revolving credit facility and the principal amount of any Advance that is repaid may not be re-borrowed and shall be a permanent reduction of the Equity Credit Facility Commitment.

~~(4) Any amount of TPC's Construction Cash Call Requirement that TPC pays to the Limited Partnership using funds that are not funded by an Advance under the Equity Credit Facility shall be a permanent reduction of the Equity Credit Facility Commitment.~~

~~**2.3 Available Advances.**~~

~~(1) Hydro shall, on the terms and conditions of this Agreement, make the Equity Credit Advances available to TPC under the Equity Credit Facility in accordance with Section 4.2.~~

~~(2) All Equity Credit Advances requested hereunder shall be made available to TPC in accordance with Article IV.~~

~~**2.4 Use of Proceeds.**~~

~~TPC shall use the proceeds of Advances under the Equity Credit Facility only for payment to the Limited Partnership of all amount(s) required to be paid to the Limited Partnership by TPC, in its capacity as a limited partner of the Limited Partnership, for capital contributions in accordance with and subject to the provisions of the Limited Partnership Agreement pursuant to demands made by the General Partner:~~

~~(a) prior to the Final Closing Date; and~~

~~(b) on or after the Final Closing Date but immediately prior to the first Anniversary Date if such capital contribution is required by the Limited Partnership to fund costs related to the construction of the Wuskwatim Project (collectively, "**TPC's Construction Cash Call Requirements**" and individually, "**TPC's Construction Cash Call Requirement**");~~

~~other than such of TPC's Construction Cash Call Requirements that TPC elects to pay to the Limited Partnership using Approved Funds and not through the proceeds of Equity Credit Advances (in which event such amounts shall form part of TPC's Invested Cash, being either TPC's Own Funds or TPC's Third Party Funds as determined by Hydro in accordance with Section 10.2(11) after Hydro's receipt from TPC of the Limited Partnership Payment Certification). For greater certainty, where TPC's Construction Cash Call Requirement is received by TPC, and TPC does not intend to use an Equity Credit Advance to fund such capital contribution, it shall forward a Limited Partnership Payment Certification to Hydro in accordance with Section 10.2(11). If Hydro approves the proposed payment, TPC shall pay directly to the Limited Partnership the amount of TPC's Construction Cash Call Requirement no later than three (3) Business Days prior to the due date specified in the demand notice from the General Partner. If the Limited Partnership Payment Certification is not approved by Hydro or if TPC did not forward a Limited Partnership Payment Certification to Hydro in accordance with~~

~~the requirements of Section 10.2(11) or otherwise intended to fund the capital amount through an Equity Credit Advance, it shall issue a Borrowing Notice to Hydro for such amount in accordance with the provisions of this Agreement (if Hydro has not received confirmation at least two (2) Business Days prior to the due date specified in the demand notice from the General Partner that the capital contribution has been paid, a Borrowing Notice shall have been deemed to have been received by Hydro from TPC for the amount of the capital contribution and Hydro shall proceed to fund the TPC's Construction Cash Call Requirement as an Equity Credit Advance in accordance with Section 4.2. Hydro shall provide notice to TPC of any amount so advanced to the Limited Partnership on behalf of TPC.) No Advances shall be made to TPC under the Equity Credit Facility at any time prior to the Initial Closing Date nor on or after the first Anniversary Date.~~

2.3 ~~2.5~~ Repayment on the Maturity Date.

Subject to Hydro making an early demand for payment pursuant to Section 12.1 following an Event of Default, TPC shall repay on the Maturity Date, the Total Outstandings, if any, under the Equity Credit Facility and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility, and the Total Outstandings, if any, under the Equity Credit Facility and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility shall become due and payable on the Maturity Date. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.

2.4 ~~2.6 Mandatory Repayments during the Term of the Agreement.~~Balances as at Final Closing and TPC Payments.

~~(1) If, on any day, Hydro notifies TPC that the Total Outstandings under the Equity Credit Facility exceeds the Equity Credit Facility Commitment (the "**Equity**~~

~~**Credit Over-Drawn Amount**"), TPC shall repay to Hydro, an amount sufficient to reduce the said Total Outstandings to an amount equal to or less than the Equity Credit Facility Commitment. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.~~

~~(2) At any time prior to the Maturity Date, provided TPC is not in default of any material provision of the Loan Documents and subject to Section 2.6(3) and Article VI and TPC's right to make prepayments in accordance with the provisions of this Agreement, the Equity Credit Over-Drawn Amount and all accrued and unpaid interest thereon will during the term of this Agreement be repaid solely through Hydro receiving all Distributions from time to time on TPC's Loan Units. The Distributions on TPC's Loan Units shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents to be applied as follows: first, in repayment of all costs and expenses owing to Hydro under this Agreement and which arise in connection with the Equity Credit Over-Drawn Amount; second, in payment of all accrued and unpaid interest on the Equity Over-Drawn Amount; and third, in repayment of the Equity Credit Over-Drawn Amount. (For greater certainty, if any of the said amounts are still outstanding on the Maturity Date, they shall be required to be repaid on the Maturity Date, in accordance with Section 2.5). Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro, as provided for under the Security Documents, until the Equity Credit Over-Drawn Amount and the aforesaid costs, expenses and interest have been repaid in full.~~

~~(3) In addition to all other mandatory payment obligations provided for in this Agreement, if~~The Parties agree and acknowledge that, at the Time of Final Investment Closing, ~~all of the following conditions are not met, TPC shall make a capital contribution to the~~

~~Limited Partnership using Approved Funds, or shall repay such portion of the aggregate of outstanding Advances under the Equity Credit Facility using Approved Funds, as may be required in order to~~TPC shall comply with each of the following conditions: ;

(a) TPC's Invested Cash ~~at the Time of Final Closing must be equal to or greater than $5,000,000;~~is twenty-one million, one hundred and seventy-eight thousand ($21,178,000.00) dollars, exclusive of accrued interest;

~~(b) the Total Outstandings under the Equity Credit Facility at the Time of Final Closing must not be greater than four times TPC's Invested Cash at the Time of Final Closing; and~~

~~(c) the Total Outstandings under the Equity Credit Facility at the Time of Final Closing must not be greater than twenty-two (22%) percent of the Aggregate Capital Contributions immediately following the Final Closing.~~

~~(The conditions referred to in paragraphs (a), (b) and (c) of this Section 2.6(3) are collectively referred to as the "**Equity Credit Facility Final Closing Conditions**").~~

~~In the event that TPC is not in compliance with any of the aforementioned conditions on the date that is forty (40) calendar days prior to the Final Closing Date, Hydro shall, not less than thirty (30) calendar days prior to the Final Closing Date, provide a notice of non-compliance to TPC, together with particulars as to TPC's deficiencies in respect of these conditions, and notice of the amount of the capital contribution to the Limited Partnership or the amount of the principal repayment under the Equity Credit Facility, as the case may be, that is required in order to bring TPC into good standing with the aforementioned conditions. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts, and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.~~

~~(4) In addition to all other mandatory payment obligations provided for in this Agreement, if at the Time of Adjustment, all of the following conditions are not met, TPC shall make a capital contribution to the Limited Partnership using Approved Funds or shall repay such portion of the aggregate of outstanding Advances under the Equity Credit Facility using Approved Funds, as may be required in order to comply with each of the following conditions:~~

~~(a) the Total Outstandings under the Equity Credit Facility at the Time of Adjustment must not be greater than four (4) times TPC's Invested Cash (excluding any amounts paid to the Limited Partnership for TPC's Operating Cash Call Requirement(s) or paid to Hydro in repayment of Cash Call Credit Advances) at the Time of Adjustment; and~~

(b) ~~the~~The Total Outstandings under the Equity Credit Facility ~~at the Time of Adjustment must not be greater than twenty-two (22%) percent of the Aggregate Capital Contributions (excluding any amount paid to the Limited Partnership for TPC's Operating Cash Requirement(s)) immediately following the first Anniversary Date.~~is eight-seven million six hundred twelve thousand dollars ($87,612,000.00); and

~~(The conditions referred to in paragraphs (a) and (b) of this Section 2.6(4) are collectively referred to as the "**Equity Credit Facility Adjustment Conditions**").~~

~~In the event that TPC is not in compliance with any of the aforementioned conditions on the date that is forty (40) calendar days prior to the first Anniversary Date, Hydro shall, not less than thirty (30) calendar days prior to the first Anniversary Date, provide a notice of non-compliance to TPC, together with particulars as to TPC's deficiencies in respect of these conditions, and notice of the amount of the capital contribution to the Limited Partnership or the amount of~~

~~the principal repayment under the Equity Credit Facility, as the case may be, that is required in order to bring TPC into good standing with the aforementioned conditions. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.~~

(c) ~~(5)~~ In addition to all other mandatory payment obligations provided for in this Agreement and subject to TPC's right to make prepayments in accordance with the provisions of this Agreement, TPC shall throughout the term of this Agreement repay to Hydro all outstanding Advances under the Equity Credit Facility and accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility solely through Hydro receiving all Distributions from time to time on TPC's Loan Units. The Distributions on TPC's Loan Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Equity Credit Facility; second, in payment of all accrued and unpaid interest under the Equity Credit Facility (except as dealt with under subsection (2) above); and third, in repayment of all principal amounts that have not been repaid under the Equity Credit Facility (except as dealt with under subsection (2) above). (For greater certainty, any of the said amounts owing under the Equity Credit Facility on the Maturity Date shall be required to be repaid on the Maturity Date in accordance with Section 2.5). Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until the Total Outstandings under the Equity Credit Facility and any accrued and unpaid interest thereon and all other amounts owing to Hydro under the Equity Credit Facility have been repaid in full. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents. The amount of any repayment shall be a permanent reduction of the Equity Credit Facility Commitment.

~~(6) Notwithstanding any other provision of this Agreement, if, after Final Closing and all mandatory payment obligations have been met by TPC in accordance with the provisions of this Agreement, the number of TPC's Loan Units is not greater than or equal to the number of TPC's Cash Units or if TPC owns only TPC's Cash Units, all of the interest that accrued on the outstanding Equity Credit Advances under the Equity Credit Facility during the Construction Period (including any interest that accrued on an Equity Credit Advance that was repaid on Final Closing), and which remains unpaid on the Final Closing Date, shall, subject to TPC's right to prepay the said amount in accordance with the provisions of this Agreement, be paid solely through Hydro receiving all Distributions from time to time on TPC's Cash Units. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until all of the said accrued interest as at the Final Closing Date has been repaid in full, and upon repayment in full of the said interest amount, Hydro shall have no further right to any Distributions on TPC's Cash Units for repayment of Equity Credit Advances or interest thereon provided that TPC is not in default under the provisions of the Loan Documents. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.~~

~~2.7~~ 2.5 Optional Reductions.

~~(1)~~ TPC may subject to the provisions of this Agreement, including ~~Section 2.7(2)~~Sections 4.5 and ~~Section~~ 4.6 as adjusted for the applicable Market Make-whole Payment in accordance with Section ~~13.9,~~13.11, prepay, in whole or in part, only with Approved Funds, the Total Outstandings under the Equity Credit Facility, at any time, without penalty~~.~~ as long as each partial prepayment made by TPC under the Equity Credit Facility shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.

~~(2) Each partial prepayment made by TPC under the Equity Credit Facility shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.~~

ARTICLE III

~~CASH CALL CREDIT FACILITY~~

PRIORITY OF DISTRIBUTION PAYMENTS

3.1 ~~Cash Call Credit Facility.~~[intentionally blank]

~~Hydro agrees, on the terms and conditions of this Agreement, to make available to TPC at any time after the Final Closing Date the Cash Call Credit Facility by making such Advances to TPC as may be requested by TPC at any time and from time to time after the Final Closing Date hereunder in accordance with this Agreement.~~

3.2 ~~Credit Facility Commitment and Facility Limit.~~[intentionally blank]

~~(1) Hydro shall not be obliged to make any Cash Call Credit Advance or Cash Call Credit Advances which would cause the Total Outstandings under the Cash Call Credit Facility to be greater than the Cash Call Credit Facility Commitment~~

~~provided that if no Event of Default has otherwise occurred that remains outstanding and uncured at that time, Hydro shall advance in accordance with the provisions of this Agreement as a Cash Call Credit Advance to TPC, upon request, the lesser of the amount requested by TPC and the amount hereunder which would, when advanced, cause the Total Outstandings with respect to the Cash Call Credit Facility to equal, but not exceed, the Cash Call Credit Facility Commitment.~~

~~(2) The Cash Call Credit Facility may be drawn upon by TPC at any time after the Final Closing Date if an amount is required to be paid by TPC to the Limited Partnership pursuant to TPC's Operating Cash Call Requirements subject to the terms and conditions of this Agreement.~~

~~(3) The Cash Call Credit Facility is a non-revolving credit and the principal amount of any Advance that is repaid may not be re-borrowed and shall be a permanent reduction of the Cash Call Credit Facility Commitment.~~

~~(4) Any amount of TPC's Operating Cash Call Requirements that TPC pays to the Limited Partnership using funds that are not funded by an Advance under the Cash Call Credit Facility shall be a permanent reduction of the Cash Call Credit Facility Commitment.~~

3.3 ~~Available Advances.~~[intentionally blank]

~~(1) Hydro shall, on the terms and conditions of this Agreement, make the Cash Call Credit Advances available to TPC under the Cash Call Credit Facility in accordance with Section 4.2.~~

~~(2) All Cash Call Credit Advances requested hereunder shall be made available to TPC in accordance with Article IV.~~

3.4 ~~Use of Proceeds.~~[intentionally blank]

~~TPC shall use the proceeds of Advances under the Cash Call Credit Facility only for payment to the Limited Partnership of all amount(s) required to be paid to the Limited Partnership by TPC, in its capacity as a limited partner of the Limited Partnership, for capital contributions in accordance with and subject to the provisions of the Limited Partnership Agreement pursuant to demands made by the General Partner:~~

~~(a) on or after the first Anniversary Date; and~~

~~(b) on or after the Final Closing but prior to the first Anniversary Date if such capital amount is required by the Limited Partnership to fund shortfalls in operating revenues or due to other matters relating to the business of the Limited Partnership other than on account of costs related to the construction of the Wuskwatim Project (collectively, "**TPC's Operating Cash Call Requirements**", and individually, "**TPC's Operating Cash Call Requirement**");~~

~~other than such of TPC's Operating Cash Call Requirements that TPC elects to pay to the Limited Partnership using Approved Funds and not through the proceeds of Cash Call Credit Advances (in which event such amounts shall form part of TPC's Invested Cash, being either TPC's Own Funds or TPC's Third Party Funds as determined by Hydro in accordance with Section 10.2(11) after Hydro's receipt from TPC of the Limited Partnership Payment Certification). For greater certainty, where TPC's Operating Cash Call Requirement is received by TPC, and TPC does not intend to use a Cash Call Credit Advance to fund such capital contribution, it shall forward a Limited Partnership Payment Certification to Hydro in accordance with Section 10.2(11). If Hydro approves the proposed payment, TPC shall pay~~

~~directly to the Limited Partnership the amount of TPC's Operating Cash Call Requirement no later than three (3) Business Days prior to the due date specified in the demand notice from the General Partner. If the Limited Partnership Payment Certification is not approved by Hydro or if TPC did not forward a Limited Partnership Payment Certification to Hydro in accordance with the requirements of Section 10.2(11) or otherwise intended to fund the capital amount through a Cash Call Credit Advance, it shall issue a Borrowing Notice to Hydro for such amount in accordance with the provisions of this Agreement (if Hydro has not received confirmation at least two (2) Business Days prior to the due date specified in the demand notice from the General Partner that the capital contribution has been paid, a Borrowing Notice shall have been deemed to have been received by Hydro from TPC for the amount of the capital contribution and Hydro shall proceed to fund TPC's Operating Cash Call Requirement as an Cash Call Credit Advance in accordance with Section 4.2. Hydro shall provide notice to TPC of any amount so advanced to the Limited Partnership on behalf of TPC.) No Advances shall be made to TPC under the Cash Call Credit Facility at any time prior to the Final Closing Date nor on or after the Maturity Date.~~

3.5 ~~Repayment on the Maturity Date.~~[intentionally blank]

~~(1) The Total Outstandings, if any, under the Cash Call Credit Facility and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility shall become due and payable on the Maturity Date and subject to Hydro making an early demand for payment pursuant to Section 12.1 following an Event of Default, TPC shall repay on the Maturity Date the Total Outstandings, if any, and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Security Documents.~~

~~(2) Notwithstanding the provisions of Section 3.5(1) but subject to the provisions of Section 3.5(3), if on the Maturity Date, TPC is not in default in respect of any material provision of the Loan Documents, that proportion of the Total Outstandings under the Cash Call Credit Facility on the Maturity Date and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility that is equal to (A) divided by (B) where (A) equals the Total Outstandings under the Cash Call Credit Facility on the Maturity Date and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility multiplied by the number of TPC's Cash Units on the Maturity Date; and (B) is the number of TPC's Units on the Maturity Date (the "**Cash Unit Portion**") will be repaid to Hydro solely through Hydro receiving all Distributions from time to time on TPC's Units. The Distributions on TPC's Units shall be applied as follows: first, in payment of all costs and expenses owing to Hydro in connection with the Cash Unit Portion of the Cash Call Credit Facility; second, in payment of all accrued and unpaid interest under the Cash Unit Portion of the Cash Call Credit Facility; and third, in repayment of all principal amounts that have not been repaid under the Cash Unit Portion of the Cash Call Credit Facility. Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for in the Security Documents, until all such amounts have been repaid in full. Provided TPC is not in default in respect of any material provision of the Loan Documents (including the continued payment of the Distributions on TPC's Units to Hydro as provided for herein), no further or other payments by TPC to Hydro under this Cash Call Credit Facility will be required and TPC will be deemed in good standing in respect of its payment obligations under the Cash Call Credit Facility. For greater certainty, TPC shall continue to be bound by all provisions of the Loan Documents subsequent to the Maturity Date for such period of time as any amount is owing to Hydro under either of the Credit Facilities.~~

~~(3) Section 3.5(2) shall not affect TPC's obligation to repay on the Maturity Date that proportion of the Total Outstandings under the Cash Call Credit Facility on the Maturity Date and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility equal to (A) divided by (B) where (A) equals the Total Outstandings under the Cash Call Credit Facility on the Maturity Date and all accrued and unpaid interest thereon and all other amounts owing to Hydro under the Cash Call Credit Facility multiplied by TPC's Loan Units on the Maturity Date; and (B) is the total number of TPC's Units on the Maturity Date.~~

3.6 ~~Mandatory Repayments during the Term of the Agreement.~~[intentionally blank]

~~(1) If, on any day, Hydro notifies TPC that the Total Outstandings under the Cash Call Credit Facility exceeds the Cash Call Credit Facility Commitment (the "**Cash Call Over-Drawn Amount**"), TPC shall repay to Hydro, an amount sufficient to reduce the said Total Outstandings to an amount equal to or less than the Cash Call Credit Facility Commitment. It is acknowledged that Hydro shall have no right to sue TPC on the personal covenant to pay any of the said amounts and that Hydro's sole recourse for payment shall be to the Collateral in accordance with the provisions of the Loan Documents.~~

~~(2) At any time prior to the Maturity Date, provided that TPC is not in default of any provision of the Loan Documents and subject to TPC's right to make prepayment in accordance with the provisions of this Agreement, the Cash Call Over-Drawn Amount and all accrued and unpaid interest thereon will during the term of this Agreement be repaid to Hydro solely through Hydro receiving all Distributions from time to time on TPC's Units. The Distributions on TPC's Units shall be~~

~~applied as follows: first, in payment of all costs and expense owing to Hydro in connection with the Cash Call Over-Drawn Amount; second, in payment of all accrued and unpaid interest on the Cash Call Over-Drawn Amount; and third, in repayment of the Cash Call Over-Drawn Amount. Such Distributions shall be paid to Hydro pursuant to an irrevocable assignment and direction of all such Distributions as provided for under the Security Documents until the Cash Call Over-Drawn Amount has been repaid in full.~~

~~(3) In addition to all other mandatory repayment obligations provided for in this Agreement and subject to TPC's right to make prepayments in accordance with the provisions of this Agreement, TPC shall throughout the term of this Agreement repay to Hydro all of the Total Outstandings under the Cash Call Credit Facility and all accrued and unpaid interest thereon, and all other amounts owing to Hydro under the Cash Call Credit Facility, solely through Hydro receiving all Distributions from time to time on TPC's Units. The Distributions on TPC's Units shall be applied as follows: first, in repayment of all costs and expenses owing to Hydro in connection with the Cash Call Credit Facility; second, in payment of all accrued and unpaid interest under the Cash Call Credit Facility (except as dealt with under subsection (2) above); and third, in repayment of all principal amounts that have not been repaid under the Cash Call Credit Facility (except as dealt with under subsection (2) above). (For greater certainty, this shall not affect the repayment requirements specified in Section 3.5(3) on the Maturity Date.) Such Distributions shall be paid to Hydro pursuant to TPC's irrevocable assignment and direction of all such Distributions to Hydro as provided for under the Security Documents until all such amounts have been repaid in full. The amount of such repayment shall be a permanent reduction of the Cash Call Credit Facility.~~

3.7 Priority of Distribution Payments Prior to Maturity Date.

~~(1) The priority for the application of payments made to Hydro through~~ Hydro shall apply all payment of Distributions ~~during the term of this Agreement and~~on TPC's Units prior to ~~the~~ Maturity Date on ~~all or a portion of TPC's Units (as determined in accordance with the applicable provisions) shall be~~ as follows:

(a) first, to the payments to be made to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), which shall have priority over any payments to be made out of Distributions on TPC's Units and the security provided to Hydro pursuant to the provisions of this Agreement, and accordingly, any such payments to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement shall not constitute an Event of Default hereunder;

~~(b) second, to payments to be made to Hydro pursuant to Section 2.6(6);~~

~~(c) third, to payments to be made to Hydro pursuant to Section 3.6(2);~~

~~(d) fourth, to payments to be made to Hydro pursuant to Section 3.6(3);~~

(b) ~~(e) fifth~~second, to the payments to be made to Hydro pursuant to Section 2.5(1) of the NCN Financing Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), and, accordingly, any such payments to Hydro pursuant to the NCN Financing Agreement shall not constitute an Event of Default;

(c) ~~(f) sixth~~third, to the payments to be made to Hydro pursuant to Section 2.5(2) of the NCN Financing Agreement and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units, and any such payments to Hydro pursuant to the NCN Financing Agreement shall not constitute an Event of Default ~~hereunder;~~under this Agreement; and

~~(g) seventh, to payments to be made to Hydro pursuant to Section 2.6(2); and~~

(d) ~~(h) eighth,~~fourth to payments to be made to Hydro pursuant to Section ~~2.6~~2.4 (~~5~~c).

3.8 Priority of Distributions Payments on Maturity Date.

~~(2)~~ The priority for payments made to Hydro through Distributions on TPC's Units commencing on the Maturity Date ~~on TPC's Units~~ shall be as follows:

(a) first, to the payments to be made to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement (and the security provided to Hydro pursuant to the provisions of that agreement in respect of the Distributions on TPC's Units), which shall have priority over any payments to be made out of Distributions on TPC's Units after the Maturity Date (and the security provided to Hydro pursuant to the provisions of this Agreement) and accordingly, any such payments to Hydro pursuant to the provisions of the Revenue Advance Consolidation Agreement shall not constitute an Event of Default hereunder;

~~(b) second, to payments to be made to Hydro pursuant to Section 2.6(6);~~

~~(c) third, to the payments to be made to Hydro pursuant to Section 3.5(2); and~~

(b) ~~(d) fourth,~~ second, to the payments to be made to Hydro pursuant to the provisions of the NCN Financing Agreement (and the security provided to Hydro pursuant to the provisions of that Agreement in respect of Distributions on TPC's Units)~~.~~; and

(c) ~~(3) For~~for so long as no Event of Default has occurred that remains outstanding and uncured, and provided that Distributions on TPC's Units are applied in accordance with Section ~~3.7~~3.8 (~~1~~a) prior to the Maturity Date, and in accordance with Section ~~3.7~~3.8(~~2~~b) after the Maturity Date, pursuant to the irrevocable assignment and direction of the Distributions on TPC's Units to Hydro under the Security Documents as and when such Distributions are paid by the Limited Partnership (in the discretion of the General Partner), TPC shall have no other payment obligation under the Equity Credit ~~Facilities~~Facility or in respect of any amounts (whether principal, interest, costs or otherwise) due thereunder (except at Maturity Date in respect of such amounts as are stated to be due and payable on the Maturity Date).

~~**3.8 Optional Reductions.**~~

~~(1) TPC may, subject to the provisions of this Agreement, including Sections 3.8(2) and Section 4.6 as adjusted for the applicable Market Make-whole Payment in accordance with Section 13.9, prepay, in whole or in part, only with Approved Funds, the Total Outstandings under the Cash Call Credit Facility, at any time without penalty.~~

~~(2) Each partial repayment made by TPC under the Cash Call Credit Facility shall be in a minimum aggregate principal amount of $200,000 and in an integral multiple of $100,000.~~

ARTICLE IV
LOAN ADVANCES

~~4.1 **The Advances.**~~

~~(1) Hydro agrees, on the terms and conditions of this Agreement, to make Advances to TPC under the Equity Credit Facility at any time and from time to time prior to the first Anniversary Date, and under the Cash Call Credit Facility at any time and from time to time after the Final Closing Date, on any Business Day.~~

~~(2) Until repaid in full, each Advance shall be the Type of Advance specified in the applicable Borrowing Notice.~~

~~4.2 **Procedure for Borrowing.**~~

~~(1) Where TPC wishes to receive one or more Advance(s) under one or both of the Credit Facilities, notice (the "**Borrowing Notice**") shall be given by TPC to Hydro not later than 10:00 a.m. (Winnipeg time), at least two (2) Business Days but not more than ten (10) Business Days prior to the date of the proposed Advance(s). Each Borrowing Notice shall be irrevocable and binding on TPC and shall be in substantially the form of Schedule B and shall specify:~~

~~(a) the requested date of the Advance(s); and~~

~~(b) the amount of each Advance by Type of Advance and the aggregate amount of the Advances comprising such Borrowing.~~

~~Subject to the terms and conditions of this Agreement, Hydro will make such funds available to TPC by forwarding immediately available funds in the amount~~

~~of the Advance(s) directly to the Limited Partnership Account for and on behalf of TPC on the specified date for each such Advance. Hydro shall provide written notice to TPC and the General Partner that the funds have been forwarded to the Limited Partnership Account on TPC's behalf in accordance with the Borrowing Notice.~~

~~(2) TPC authorizes the General Partner to provide to Hydro concurrent notice of any TPC's Construction Cash Call Requirement and any TPC's Operating Cash Call Requirement. The said notice shall be deemed to be a Borrowing Notice from TPC to Hydro for an Equity Credit Advance or Cash Call Credit Advance, as applicable, for the amount specified in the said notice, to be paid on the due date specified in the said notice. Hydro shall forward the amount of the Equity Credit Advance or Cash Call Credit Advance to the Limited Partnership Account for the credit of TPC unless at least two (2) Business Days prior to the due date specified in the said the notice Hydro receives written notice from the General Partner that the Limited Partnership has received the full amount of the TPC's Construction Cash Call Requirement or TPC's Operating Cash Call Requirement, as applicable. Hydro shall provide notice to TPC of any payment made to the Limited Partnership Account for the credit of TPC.~~

~~4.3 Interest on Advances.~~

~~Each Advance shall bear interest at the rate applicable to each Type of Advance determined in accordance with this Article IV from the date such Advance is made to the date such Advance is repaid or as otherwise stipulated in this Agreement.~~

4.1 ~~4.4~~ Interest on Equity Credit Advances.

Subject to Section 13.3, each Equity Credit Advance, or the amount ~~thereof~~ remaining outstanding from time to time, shall bear interest ~~and such interest shall be~~ calculated and payable in the following manner:

~~(a)~~ Any Equity Credit Advance forwarded to the Limited Partnership Account for the credit of TPC ~~during the Construction Period~~on or before October 14, 2014 shall:

(i) until the Final Closing Date bear interest at a variable rate (expressed as a percentage rate per annum) equal to the Canadian Dollar Floating Rate in effect from time to time, plus one (1%) percent per annum compounded monthly (not in advance), calculated (but not compounded) daily and shall accrue interest at that rate until the Final Closing Date. Hydro shall provide TPC with notice of the Canadian Dollar Floating Rate applicable to each such Equity Credit Advance, and it's supporting calculations therefore, which shall constitute, in the absence of error, prima facie evidence of the Canadian Dollar Floating Rate applicable to each such Advance;

(ii) from and after the Final Closing Date~~,~~, to and until March 31, 2014, the Total Outstandings under the Equity Credit Facility, plus all accrued and unpaid interest thereon, and all other amounts owing to Hydro under the Equity Credit Facility as at the Final Closing Date shall bear interest at a fixed interest rate ~~(expressed as a percentage rate per annum) equal to the Canadian Thirty Year Rate in effect on the Final Closing Date plus one (1%) percent per annum,~~of six and three hundred seventy-six one thousands (6.376%) percent calculated and compounded semi-annually (not in advance) ~~from and after the Final Closing Date and shall accrue interest at~~

~~that rate until the tenth Anniversary Date~~. Hydro shall provide TPC with notice of the Canadian Thirty Year Rate applicable to the amount of the Equity Credit Advances then outstanding and all accrued and unpaid interest thereon and all other amounts owning to Hydro in respect thereto, and its supporting calculations therefore, which shall constitute, in the absence of error, prima facie evidence of the applicable Canadian Thirty Year Rate;

(iii) from and after ~~the tenth Anniversary Date,~~April 1, 2014, the Total Outstandings under the Equity Credit Facility, plus all accrued and unpaid interest thereon, and all other amounts owing to Hydro under the Equity Credit Facility~~, as at the tenth Anniversary Date~~ shall bear interest at a fixed interest rate ~~(expressed as a percentage rate per annum) equal to the Canadian Thirty Year Rate in effect on the Final Closing Date plus three (3%) percent per annum~~of five and three hundred seventy-six one thousandth (5.376%) percent calculated and compounded semi-annually (not in advance);

Interest on any Equity Credit Advance made after April 1, 2014 shall accrue in the current month and added to the Total Outstandings for the purposes of the interest calculations in Section 13.3(a) (ii).

Hydro shall provide TPC with notice of the ~~Canadian Thirty Year Rate~~interest rate applicable to the amount of the Equity Credit Advances then outstanding, and all accrued and unpaid interest thereon and all other amounts owing to Hydro in respect thereto and its supporting calculations therefor~~, which shall constitute, in the absence of error, prima facie evidence of the applicable Canadian Thirty Year Rate~~; and

(iv) subject to the provisions of this Agreement (including payments made through Distributions under Article II and TPC's right to make prepayments in accordance with the provisions of this Agreement), the accrued interest, and all other amounts owing to Hydro under the Equity Credit Facility, shall only become due and payable on the Maturity Date.

~~(b)~~ Any Equity Credit Advance forwarded to the Limited Partnership Account for the credit of TPC after the Final Closing Date and prior to the first Anniversary Date shall, from the date of the Advance until ~~the tenth Anniversary Date,~~March 31, 2014, bear interest at the interest rate established pursuant to ~~paragraph (ii) of~~ Section ~~4.4.(a~~4.1(a)(ii) and, from and after ~~the tenth Anniversary Date,~~April 1, 2014, bear interest at the interest rate established pursuant to ~~paragraph~~Section 4.1(a) (iii)~~ of Section 4.4(a)~~, the provisions of which shall apply, *mutatis mutandis*, to such Advances and, subject to the provisions of this Agreement (including payments made though Distributions under Article II and TPC's right to make prepayments in accordance with the provisions of this Agreement), the accrued interest, and all other amounts owing to Hydro under the Equity Credit Facility, shall only become due and payable on the Maturity Date.

~~**4.5 Interest on Cash Call Credit Advances.**~~

~~Subject to Section 13.3, each Cash Call Credit Advance or the amount thereof remaining outstanding from time to time shall bear interest at a fixed interest rate per annum (expressed as a percentage rate per annum) equal at all times for that Cash Call Credit Advance to the Canadian Ten Year Rate in effect on the date that the said Cash Call Credit Advance is forwarded to the Limited Partnership Account for the credit of TPC, plus three (3%) percent per annum calculated and compounded semi-annually commencing from and after the date of the Advance and shall only become due and payable, subject to the provisions of this Agreement (including payments made through Distributions under Article III and TPC's right to make prepayments in accordance with the provisions of this Agreement), on the Maturity Date. Hydro~~

~~shall provide TPC with notice of the Canadian Ten Year Rates applicable to each Cash Call Credit Advance together with its supporting calculations therefor, which shall constitute, in the absence of error, prima facie evidence of the applicable Canadian Ten Year Rates to each such Advance.~~

4.2 ~~4.6~~ **Repayment Notice.**

Mandatory repayments pursuant to Sections 2.6(3) and (4) and optional repayment to reduce the Total Outstandings under the Equity Credit ~~Facilities~~Facility pursuant to Sections 2.7 and/or 3.7 shall be made upon at least seven (7) Business Days' notice (but not more than twenty (20) Business Days' notice) to Hydro (each such notice a "**Repayment Notice**"). As a condition of any Repayment Notice and the ~~aforesaid~~ payments being made to Hydro, TPC shall deliver to Hydro, at least thirty (30) calendar days prior to the proposed date that TPC intends to make the repayment, a statutory declaration signed by a duly authorized officer of TPC (each such statutory declaration a "**Credit Facility Repayment Certification**") which shall:

(a) certify ~~as to~~ the source of the money to be used ~~to make~~ for the proposed repayment ~~and shall~~;

(b) disclose all material information relating to the money to be used ~~in respect of~~ for the proposed repayment ~~and shall~~;

(c) attach ~~notarized~~true and complete copies of all material documents~~, together with~~; and

(d) a copy of the proposed Repayment Notice~~. The proposed Repayment Notice shall be~~ in the form of Schedule A ~~annexed hereto, and shall specify~~to this Agreement, specifying: (A) the proposed date of such repayment; and (B) the aggregate principal amount of the proposed repayment. Hydro shall have the right to request from TPC, within five (5) calendar days of receipt of the Credit Facility Repayment Certification, such additional information and notarized copies of documents relating to the monies to be used in respect of the proposed repayment as it may require, acting reasonably, and to receive such written consents and waivers from TPC to obtain additional information and documents from any other Person relating to the monies to be used in respect of the proposed repayment as Hydro may request, acting reasonably. Hydro shall be required to confirm in writing within twenty (20) calendar days of receipt of the Credit Facility Repayment Certification whether or not it will accept the Credit Facility Repayment Certification, unless the time period is extended by Hydro, acting reasonably, due to Hydro awaiting receipt of the additional information and documents as it may have requested in connection with the Credit Facility Repayment Certification.

4.3 Hydro Acceptance of Repayment Notice.

If Hydro accepts the Credit Facility Repayment Certification, TPC ~~shall be permitted to~~may issue to Hydro the Repayment Notice in the form attached to the Credit Facility Repayment Certification, and ~~if such Credit Facility Repayment Notice is given,~~ TPC shall:

(~~A~~a) pay Hydro~~, in accordance with such~~ the repayment amount set out the Repayment Notice~~, the amount of the repayment,~~ ; and

(b) provide with the said payment, a statutory declaration signed by a duly authorized officer of TPC certifying there has been no material change to any of the information or documents provided by TPC in the Credit Facility Repayment Certification ~~or obtained by Hydro~~ concerning the monies being paid to Hydro, including the source of the monies; and

(~~B~~c) pay to Hydro all accrued interest on the Credit Facility in respect of which the repayment is being made, to the date of such repayment. ~~(~~

For greater certainty, any principal amount repaid pursuant to the Repayment Notice are Approved Funds and form part of TPC's Invested Cash but does not include any amount on account of the payment of accrued interest on the Equity Credit Facility ~~in respect of which the repayment is being made). TPC shall not make the repayment without providing the said statutory declaration~~).. Hydro shall be required to accept the Credit Facility Repayment Certification if Hydro determines, acting reasonably, that the monies being used for the repayment fall within the definition of TPC's Own Funds based on Hydro's analysis of the information disclosed and documents provided or otherwise obtained by Hydro. ~~If based on~~

4.4 Hydro's ~~analysis~~Rejection of Funds.

If Hydro, acting reasonably, ~~Hydro~~based on its analysis, determines that the monies fall within the definition of TPC's Third Party Funds, then Hydro is entitled, ~~acting reasonably,~~ to either reject or accept the Credit Facility Repayment Certification. In making that determination, Hydro will consider~~,~~ the source of the monies, the terms of any financing, any repayment requirements associated with the monies that have been provided, whether or not any Person has recourse against TPC's Units in the event of default in respect of any financing associated with obtaining the monies and, if so, the likelihood of that right being exercised. If Hydro rejects the Credit Facility Repayment Certification, TPC shall not be entitled to proceed with the proposed repayment.

4.5 Hydro Acceptance of Certification.

If Hydro accepts the Credit Facility Repayment Certification, the payment can be made and the funds will be Approved Funds and once the payment is made, it shall form part of TPC's Invested Cash. For greater certainty, any funds used by TPC from time to time to pay any interest, costs, expenses or indemnity claims properly due to Hydro hereunder having regard for Section 5.14 of the PDA, shall not require certification or approval hereunder as Approved Funds.

4.6 ~~4.7~~ Evidence of Debt ~~and Determination of Interest Rates and Fees.~~

~~(1)~~ The indebtedness of TPC in respect of all Advances ~~hereunder~~ shall be evidenced by the account records maintained by Hydro, which shall be prima facie evidence of such indebtedness for all purposes, absent error. Hydro shall indemnify and save harmless TPC for losses suffered or costs incurred by TPC due to Hydro's failure to correctly record or calculate any amount, rate, date or other data (including calculations to determine any amount) in the account records or in statements or notices issued to TPC where such failure was due to the gross negligence or willful misconduct of Hydro or any person for whom Hydro is responsible at law. Notwithstanding the foregoing, the failure of Hydro to correctly record or calculate, rate, date or other data (including calculations to determine any amount) in the account records or in statements or notices issued to TPC ~~hereunder~~ under this Agreement shall not, however, affect the obligation of TPC to pay amounts due hereunder to Hydro in accordance with this Agreement.

4.7 Determination of Interest and Fees

~~(2)~~ For purposes of the *Interest Act* (Canada):

(a) whenever any interest under this Agreement is calculated using a rate based on a period of time other than a calendar year, such rate determined pursuant to such calculation, when expressed as an annual rate, is equivalent to (x) the applicable rate based on such period of time multiplied by (y) the actual number of days in the calendar year in which the period for which such interest or fee is calculated ends, and divided by (z) the number of days in such period of time;

(b) the principle of deemed reinvestment of interest shall not apply to any interest calculation under this Agreement; and

(c) the rates of interest stipulated in this Agreement are intended to be nominal rates and not effective rates or yields.

4.8 Hydro Obligations.

~~(3)~~ Within ten (10) Business Days of the last day of each month during this Agreement, Hydro shall provide to TPC a written statement ~~setting out the following information as at the last day of each month:~~the Total Outstandings under the Equity Credit Facility on the last day of each month, together with the following information:

~~(a) the Total Outstandings under the Equity Credit Facility, together with the following information:~~

~~(i) opening balances;~~

~~(ii)~~ (a) opening and closing balances;

~~(iii) Advances provided during the month;~~

~~(iv)~~ (b) principal repaid during the month~~, if applicable~~;

~~(v)~~ (c) interest paid or payable by TPC,~~ and applicable interest rate(s) charged to TPC~~ (together with the date(s) of any change(s) from floating rate(s) to fixed rate(s) charged on such Advances pursuant to the terms of this Agreement), during the month; and

~~(vi) any costs charged by Hydro to TPC during the month, and any reimbursements made by TPC to Hydro during the month for costs charged by Hydro to TPC.~~

~~(b) the Total Outstandings under the Cash Call Credit Facility, together with the following information:~~

~~(i) opening balances;~~

~~(ii) closing balances;~~

~~(iii) Advances provided during the month;~~

~~(iv) principal repaid during the month, if applicable;~~

~~(v) interest paid by TPC, and applicable interest rate(s) charged to TPC during the month; and~~

~~(vi)~~ (d) any costs charged by Hydro to TPC during the month, and any reimbursements made by TPC to Hydro during the month for costs charged by Hydro to TPC.

ARTICLE V

OPTIONS TO SELL TPC'S UNITS

5.1 TPC's Options ~~to~~To Sell.

~~TPC shall, in accordance with and subject to the terms of this Agreement have the following rights to require Hydro, upon the exercise by TPC of any such right, to purchase all or some of TPC's Units as hereinafter specified, and each such right is exercisable by TPC at the time and in the manner specified in this Article V (and, for greater certainty, the exercise of~~The Parties acknowledge neither the Final Closing Sale Right ~~with respect to less than all of TPC's Units~~or the Non-Completion Sale Right referenced in the Initial TPC Financing Agreement were exercised but this shall not preclude TPC from exercising the Term Sale Right, the Twenty-Fifth

Anniversary Sale Right or the Maturity Sale Right, in respect of any of TPC's Units still owned by TPC ~~after exercise of the Final Closing Sale Right):~~, which shall have the following rights:

~~(a) on the Final Closing Date, conditional only on TPC being in compliance with all of the Final Closing Sale Conditions, a one time right (the "**Final Closing Sale Right**") to sell only to Hydro, all of TPC's Units owned by TPC on the Final Closing Date or such other number of TPC's Units as TPC may elect to sell to Hydro on the Final Closing Date (the "**Final Closing Sale Units**"), and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Final Closing Sale Units from TPC in accordance with and subject to the provisions of this Agreement, provided that TPC shall not have the right to sell less then all of TPC's Units if TPC is not in compliance with Section 2.6(3)(a);~~

~~(b) if the Initial Closing Conditions have been satisfied in the manner contemplated in the PDA and the Initial Closing has occurred, but the Limited Partnership has not made a Substantial Construction Start within five (5) years of the Date of the PDA, or makes a Substantial Construction Start but halts construction pursuant to Section 2.6 of the PDA and has not restarted construction of the Wuskwatim Project within five (5) years of the date that construction was halted (the date upon which the applicable five year period has lapsed is referred to herein as the "**Non-Completion Date**"), TPC shall have a one time right, conditional only on TPC being in compliance with all of the Non Completion Closing Conditions (the "**Non-Completion Sale Right**"), exercisable at any time on or after the Non-Completion Date and before the date that is twenty (20) calendar days after the Non-Completion Date, to sell only to Hydro all of TPC's Units (but not less then all of TPC's Units) owned by TPC on the Non-Completion Date (the "**Non-Completion Sale Units**") and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Non-Completion Sale Units from TPC in accordance with and subject to the provisions of this Agreement;~~

(a) ~~(c)~~ on the twenty-fifth Anniversary Date, a one time right, conditional only on TPC being in compliance with all of the Twenty-Fifth Anniversary Sale Conditions (the "**Twenty-Fifth Anniversary Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the twenty-fifth Anniversary Date (the "**Twenty-Fifth Anniversary Sale Units**"), and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Twenty-Fifty Anniversary Sale Units from TPC in accordance with and subject to the provisions of this Agreement;

(b) ~~(d)~~ on the Maturity Date, a one time right, conditional only on TPC being in compliance with all of the Maturity Sale Conditions (the "**Maturity Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the Maturity Date (the "**Maturity Sale Units**"), and upon the exercise of such right, Hydro shall purchase all, and not less than all, of the Maturity Sale Units from TPC in accordance with and subject to the provisions of this Agreement; and

~~(e)~~ (c) at any time on or prior to the Maturity Date, a one -time right, conditional only on TPC being in compliance with the Term Sale Conditions, (the "**Term Sale Right**") to sell only to Hydro, all of TPC's Units (but not less than all of TPC's Units) owned by TPC on the date of exercise of such right (the "**Term Sale Units**"), and upon any exercise of such right, Hydro shall purchase all, and not less than all, of the Term Sale Units from TPC in accordance with the provisions of this Agreement.

Provided the ~~Final Closing Sale Right, Non-Completion Sale Right,~~ Twenty-Fifth Anniversary Sale Right, Maturity Sale Right or Term Sale Right is exercised by TPC in the manner set out ~~herein~~in this Agreement, and subject only to TPC's compliance with the Final Closing Sale Conditions, Non-Completion Sale Conditions, Twenty-Fifth Anniversary Sale

Conditions, Maturity Sale Conditions, or Term Sale Conditions, as applicable, Hydro ~~hereby agrees to~~ shall purchase all of the ~~Final Closing Sale Units, Non-Completion Sale Units,~~ Twenty-Fifth Anniversary Sale Units, Maturity Sale Units or Term Sale Units, as applicable, in accordance with and subject to the terms of this Agreement.

5.2 ~~5.2~~ Purchase Price~~.~~ 25th Anniversary Sale

~~(1) The purchase price for the Final Closing Sale Units which are to be sold to, and purchased by, Hydro pursuant to exercise by TPC of the Final Closing Sale Right shall be determined as follows:~~

~~(a) if the Final Closing Sale Units constitute all of TPC's Units, the purchase price shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, and all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Final Closing Date, and (B) is TPC's Invested Cash as at the Final Closing Date. The purchase price as so determined shall be paid in full as follows:~~

~~(i) by Hydro accepting the Final Closing Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Credit Facilities, and of all accrued and unpaid interest, costs and all other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Final Closing Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and~~

~~(ii) by Hydro paying to TPC on the effective date of the sale of the Final Closing Sale Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII and the payment effected thereby shall terminate the Credit Facilities and the Dividend Credit Facility (as defined under the NCN Financing Agreement).~~

~~(b) if the Final Closing Sale Right is exercised in respect of less than all of TPC's Units and the number of the Final Closing Sale Units is less than or equal to the number of TPC's Loan Units, the purchase price shall be the sum of: (A) the amount determined by multiplying the Sale Fraction by the Final Closing Date Principal Obligations, where the "Sale Fraction" is the fraction, the numerator of which is the number of the Final Closing Sale Units and the denominator of which is the number of TPC's Loan Units; and (B) the amount determined by multiplying the Interest Sale Fraction by the Final Closing Date Interest Obligations, where the "Interest Sale Fraction" is the fraction, the numerator of which is the number of Final Closing Sale Units and the denominator of which is the number of TPC's Units. The purchase price as so determined shall be paid in full as follows:~~

~~(i) if the number of Final Closing Sale Units is less than the number of TPC's Loan Units, the Final Closing Sale Units shall be retained by Hydro in full and final satisfaction of:~~

~~(A) that portion of the Final Closing Date Principal Obligations equal to the Sale Fraction multiplied by the Final Closing Date Principal Obligations, and the repayment effected thereby shall (to the extent only of the Total Outstandings that are repaid) constitute a~~

~~permanent reduction of the Equity Credit Facility Commitment; and~~

~~(B) that portion of the Final Closing Date Interest Obligations equal to the Interest Sale Fraction multiplied by the Final Closing Date Interest Obligations; and~~

~~(ii) if the number of Final Closing Sale Units is equal to the number of TPC's Loan Units, the Final Closing Sale Units shall be retained by Hydro in full and final satisfaction of:~~

~~(A) all of the Final Closing Date Principal Obligations due to Hydro, and Hydro shall fully and finally release and discharge TPC for all of the Final Closing Date Principal Obligations due to Hydro, and the repayment effected thereby shall terminate the right of TPC to receive additional Equity Credit Advances ; and~~

~~(B) that portion of the Final Closing Date Interest Obligations equal to the Interest Sale Fraction multiplied by the Final Closing Date Interest Obligation.~~

~~(c) if the Final Closing Sale Right is exercised in respect of less than all of TPC's Units and the number of the Final Closing Sale Units is greater than the number of TPC's Loan Units, the purchase price shall be an amount equal to the sum of (A) and (B) and (C), where (A) is the Final Closing Date Principal Obligations, (B) is that portion of the Final Closing Date Interest Obligations equal to the Interest Sale Fraction multiplied by the Final Closing Date Interest Obligations; and (C) is TPC's Invested Cash multiplied by the fraction, the numerator of which is the number of TPC's Cash Units that are included in the Final Closing Sale~~

~~Units and the denominator of which is the total number of TPC's Cash Units as at the Final Closing Date. The purchase price as so determined shall be paid in full as follows:~~

~~(i) by Hydro accepting the Final Closing Sale Units in full and final satisfaction of:~~

~~(A) all of the Final Closing Date Principal Obligations and by Hydro fully and finally releasing and discharging TPC for all of the Final Closing Date Principal Obligations due to Hydro; and~~

~~(B) that portion of the Final Closing Date Interest Obligations equal to the Interest Sale Fraction multiplied by the Final Closing Date Interest Obligations; and~~

~~(ii) by Hydro paying to TPC on the effective date of the sale of the Final Closing Sale Units, an amount in immediately available funds equal to TPC's Invested Cash multiplied by the fraction, the numerator of which is the number of TPC's Cash Units that are included in the Final Closing Sale Units and the denominator of which is the total number of TPC's Cash Units as at the Final Closing Date, which amount shall be paid, without interest, in accordance with Article VII and the repayment effected thereby shall terminate the right of TPC to receive Equity Credit Advances.~~

~~(2) The purchase price for the Non-Completion Sale Units which are sold to, and purchased by, Hydro pursuant to exercise by TPC of the Non-Completion Sale Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, and all accrued and unpaid interest, costs and all other amounts whatsoever owing by~~

~~TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Non-Completion Date, and (B) is TPC's Invested Cash as at the Non Completion Date. The purchase price as so determined shall be paid in full as follows:~~

~~(a) by Hydro accepting the Non-Completion Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility and all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Non-Completion Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and~~

~~(b) by Hydro paying to TPC on the effective date of the sale of the Non-Completion Sale Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII and the repayment effected thereby shall terminate the Credit Facilities and the Dividend Credit Facility (as defined under the NCN Financing Agreement).~~

~~(3)~~ The purchase price for the Twenty-Fifth Anniversary Sale Units which are sold to and purchased by, Hydro pursuant to the exercise by TPC of the Twenty-Fifth Anniversary Sale Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit ~~Facilities~~Facility, the Total Outstandings defined under the NCN Financing Agreement ~~(as defined therein)~~ and all accrued and unpaid interest, costs and other amounts ~~whatsoever~~ owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant ~~hereto and thereto~~to each agreement, as of the twenty fifth Anniversary Date, and (B) is TPC's Invested Cash ~~(specifically excluding any~~

~~Government Funds which were a component of TPC's Invested Cash)~~ as at the twenty fifth Anniversary Date. The purchase price as so determined shall be paid in full by Hydro as follows:

~~(a)~~ (a) by Hydro accepting the Twenty-Fifth Anniversary Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit ~~Facilities~~Facility hereunder and under the Dividend Credit Facility (as defined under the NCN Financing Agreement), and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the twenty fifth Anniversary Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and

~~(b)~~ (b) by Hydro paying to TPC on the effective date of the sale of the Twenty-Fifth Anniversary Sale Units, an amount in immediately available funds equal to TPC's Invested Cash ~~(specifically excluding any Government Funds which were a component of TPC's Invested Cash)~~, without interest, in accordance with Article VII; and the repayment effected thereby shall terminate the Equity Credit Facilities and the Dividend Credit Facility ~~(as defined under the NCN Financing Agreement)~~.

5.3 Purchase Price Maturity Date.

~~(4)~~ The purchase price for the Maturity Sale Units which are sold to and purchased by, Hydro pursuant to the exercise by TPC of the Maturity Sale Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit ~~Facilities~~Facility, the Total Outstandings defined under the NCN Financing Agreement

~~(as defined therein)~~ and all accrued and unpaid interest, costs and other amounts ~~whatsoever~~ owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant ~~hereto and thereto~~to each agreement, as of the Maturity Date, and (B) is TPC's Invested Cash ~~(specifically excluding any Government Funds which were a component of TPC's Invested Cash as at the Maturity Date)~~. The purchase price as so determined shall be paid in full by Hydro as follows:

(a) by Hydro accepting the Maturity Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit ~~Facilities hereunder~~ Facility and ~~under~~ the Dividend Credit Facility ~~(as defined under the NCN Financing Agreement)~~, and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant ~~hereto and thereto,~~ to each agreement as of the Maturity Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents ~~hereunder and thereunder~~under each agreement; and

~~(b)~~ (b) by Hydro paying to TPC on the effective date of the sale of the Maturity Sale Units, an amount in immediately available funds equal to TPC's Invested Cash ~~(specifically excluding any Government Funds which were a component of TPC's Invested Cash)~~ , without interest, in accordance with Article VII; and the repayment effected thereby shall terminate the Equity Credit ~~Facilities~~Facility and the Dividend Credit Facility (as defined under the NCN Financing Agreement).

5.4 Purchase Price Term Sale.

~~(5)~~ The purchase price for the Term Sale Units which are sold to, and purchased by, Hydro, pursuant to the exercise by TPC of the Term Sale Right shall be an amount equal to the aggregate of the Total Outstandings under the Credit Facilities, the Total Outstandings defined under the NCN Financing Agreement ~~(as defined therein)~~ and all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the effective date of the sale pursuant to the exercise by TPC of the Term Sale Right. The purchase price as so determined shall be paid in full by Hydro accepting the Term Sale Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit ~~Facilities hereunder~~ Facility and ~~under~~ the Dividend Credit Facility ~~(as defined under the NCN Financing Agreement),~~ and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant ~~hereto and thereto~~to each agreement, as of the effective date of the sale pursuant to the exercise by TPC of the Term Sale Right, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents ~~hereunder and thereunder~~pursuant to each agreement and the repayment ~~effected thereby~~ shall terminate the Equity Credit ~~Facilities~~Facility and the Dividend Credit Facility ~~(as defined under the NCN Financing Agreement).~~ .

~~(6) For greater certainty, whenever in this Agreement, Government Funds are to be excluded from TPC's Invested Cash, it is acknowledged that funds which were provided or advanced to TPC or NCN by Canada or Manitoba, or by any crown corporation, agency, department or instrumentality of Canada or Manitoba, and were used by TPC to repay any principal amount under a Credit Facility that Hydro has approved pursuant to a Credit Facility Repayment Certification, or to make a payment to the Limited Partnership that Hydro has approved pursuant to a Limited Partnership Payment Certification, and were determined by Hydro to be TPC's Own Funds but not Government Funds pursuant and subject to the applicable approval process, shall be included as part of TPC's Invested Cash, including in determining the amount to be repaid to TPC under any provision hereof.~~

~~5.3 Exercise of Final Closing Sale Right, Non-Completion Sale Right, Twenty Fifth Anniversary Sale Right, Maturity Sale Right and Term Sale Right~~5.5 Exercise of TPC's Sale Rights and Hydro's Notice Covenant.

~~The Final Closing Sale Right, the Non-Completion Sale Right, the~~The Twenty Fifth Anniversary Sale Right and the Term Sale ~~Right~~ may only be exercised by giving notice to Hydro in the manner set out in Section 5.4 (a "**Notice of Sale**"). Hydro agrees to provide to TPC not less than forty five (45) calendar days, nor more than ninety (90) calendar days, prior written notice of the ~~Final Closing Date or the Non-Completion Date, as applicable, and not less than forty five (45) calendar days, nor more than ninety (90) calendar days, prior written notice of the~~ Twenty-Fifth Anniversary Date or the Maturity Sale Date, as applicable, which notice shall include the following information:

(a) Hydro's calculation of the number of TPC's Units that are TPC's Loan Units and the number that are TPC's Cash Units as of the date of the notice (together with its supporting calculations); and

(b) the Total Outstandings owing under ~~each of~~ the Equity Credit ~~Facilities~~Facility, and the amount of any accrued interest and costs that is owing to Hydro, as of the notice date (having regard in respect of costs to Section 12.2).

~~5.4~~ 5.6 Contents of a Notice of Sale.

A Notice of Sale shall only be effective if:

(a) ~~(a)~~ it is executed by TPC and it indicates the number of TPC's Units in respect of which TPC is exercising its right to sell and, if the number of TPC's Units in respect of which its right to sell is being exercised is not specified in the

Notice of Sale, TPC shall be deemed to be exercising its right to sell to Hydro all of TPC's Units;

~~(b) for the exercise of the Final Closing Sale Right and subject to Hydro complying with its notice obligation in Section 5.3, the Notice of Sale must be delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the Final Closing Date, together with a statement from TPC:~~

~~(i) confirming TPC has elected to sell the Final Closing Sale Units pursuant to the Final Closing Sale Right; and~~

~~(ii) representing and warranting that each of the Final Closing Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;~~

~~which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;~~

~~(c) for the exercise of the Non-Completion Sale Right and subject to Hydro complying with its notice obligation in Section 5.3, the Notice of Sale must be delivered to Hydro not more than twenty (20) calendar days after the Non-Completion Date, together with a statement from TPC:~~

~~(i) confirming TPC has elected to sell the Non-Completion Sale Units pursuant to the Non- Completion Sale Right; and~~

~~(ii) representing and warranting that each of the Non-Completion Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;~~

~~which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;~~

(b) ~~(d)~~ for the exercise of the Twenty-Fifth Anniversary Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the Twenty-Fifth Anniversary Date, together with a statement from TPC:

(i) confirming TPC has elected to sell the Twenty-Fifth Anniversary Sale Units pursuant to the Twenty-Fifth Anniversary Sale Right; and

(ii) representing and warranting that each of the Twenty-Fifth Anniversary Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;

~~(e)~~ (c) for the exercise of the Maturity Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the Maturity Date, together with a statement from TPC:

(ii) ~~(i)~~ confirming TPC has elected to sell the Maturity Sale Units pursuant to the Maturity Sale Right; and

(iii) ~~(ii)~~ representing and warranting that each of the Maturity Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC;

~~(f)~~ (d) for the exercise of the Term Sale Right, it is delivered to Hydro at least twenty (20) calendar days (but not more than forty (40) calendar days) prior to the proposed effective date of the sale of the Term Sale Units pursuant to the exercise of the Term Sale Right, together with a statement from TPC:

(i) confirming TPC has elected to sell the Term Sale Units pursuant to the Term Sale Right; and

(ii) representing and warranting that each of the Term Sale Conditions is true and correct in all material respects on that date and will be true and correct in all material respects on the Sale Closing Date;

which statements shall be certified as true and correct in all material respects by a duly authorized officer of TPC for and on behalf of TPC.

~~5.5~~ 5.7 Effect of the Notice of Sale and Closing Arrangements.

If a Notice of Sale is sent to Hydro in compliance with Section 5.4, then:

~~(a)~~ (a) TPC shall be obligated to sell the applicable Sale Units to Hydro at the purchase price and in the manner determined in accordance with Section 5.2;

~~(b)~~ (b) Hydro shall be obligated to purchase the applicable Sale Units from TPC at the purchase price and in the manner determined in accordance with Section 5.2; and

~~(c)~~ (c) such Sale shall be completed on the date, at the place and in the manner determined in accordance with the provisions of Article VII.

ARTICLE VI

~~OPTIONS TO PURCHASE TPC'S UNITS~~

~~6.1 Hydro's Options to Purchase.~~

~~Hydro shall, in accordance with and subject to the terms of this Agreement have the following rights to require TPC, upon the exercise by Hydro of any such rights, to purchase all or some of TPC's Units as hereinafter specified, and each such right is exercisable by Hydro at the time and in the manner specified in this Article VI (and, for greater certainty, the exercise of the Final Closing Purchase Right with respect to less than all of TPC's Units shall not preclude Hydro from exercising the Adjustment Purchase Right in respect of any of TPC's Units still owned by TPC after exercise of the Final Closing Purchase Right):~~

~~(a) if Hydro has complied with the notice requirement in Section 2.6(3) and at the Time of Final Closing, TPC is not in compliance with the Equity Credit Facility Final Closing Conditions and has not by that time either made the mandatory payments or contributions required pursuant to Section 2.6(3), or exercised its Final Closing Sale Right in such manner so as, to bring itself into compliance with the Equity Credit Facility Final Closing Conditions (the "**Final Closing Purchase Option Event**"), Hydro shall, in accordance with and subject to the terms of this Agreement, have the right (the "**Final Closing Purchase Right**") to purchase such number of TPC's Loan Units (except that the parties hereto agree that this right to purchase shall be extended to all of TPC's Units, if TPC is not in compliance with Section 2.6(3)(a)) as of the Final Closing Date as is required for TPC to be brought into compliance with the Equity Credit Facility Final Closing Conditions (but no more than that number) as of the Final Closing Date (the "**Final Closing Purchased Units**"). Upon the exercise of such rights, TPC shall~~

~~sell all and not less than all of the Final Closing Purchased Units in accordance with the provisions of this Agreement;~~

~~(b) if Hydro has complied with the notice requirement in Section 2.6(4) and at the Time of Adjustment, TPC is not in compliance with the Equity Credit Facility Adjustment Conditions and has not by that time either made the mandatory payments or contributions required pursuant to Section 2.6(4) (the "**Adjustment Purchase Option Event**"), Hydro shall in accordance with and subject to the terms of this Agreement, have the right (the "**Adjustment Purchase Right**") to purchase such number of TPC's Loan Units as of the first Anniversary Date as is required for TPC to be brought into compliance with the Equity Credit Facility Adjustment Conditions (but no more than that number) as of the first Anniversary Date (the "**Adjustment Purchased Units**"). Upon the exercise of such right, TPC shall sell all and not less than all of the Adjustment Purchased Units in accordance with the provisions of this Agreement; and~~

~~(c) if a Non Completion Date occurs and notwithstanding Hydro's compliance with the notice requirement in section 5.3 hereof, by the date that is twenty-one (21) Business Days after the Non Completion Date, Hydro has not received from TPC an effective Notice of Sale in accordance with Article V (the "**Non-Completion Purchase Option Event**"), Hydro shall, in accordance with and subject to the terms of this Agreement, have the right (the "**Non-Completion Purchase Right**") to purchase all of TPC's Units (the "**Non-Completion Purchased Units**"). Upon the exercise of such right, TPC shall sell all and not less than all of the Non-Completion Purchased Units in accordance with the provisions of this Agreement.~~

~~**6.2 Purchase Price.**~~

~~(1) If TPC has complied with Section 2.6(3)(a), the purchase price for the Final Closing Purchased Units to be purchased by Hydro pursuant to the exercise of the Final Closing Purchase Right shall be the sum of: (A) the amount determined by multiplying the Purchase Fraction by the Final Closing Date Principal Obligations, where the "Purchase Fraction" for the purposes of this paragraph (1) is the fraction, the numerator of which is the number of Final Closing Purchased Units and the denominator of which is the number of TPC's Loan Units; and (B) the amount determined by multiplying the Interest Purchase Fraction by the Final Closing Date Interest Obligations, where the "Interest Purchase Fraction" for the purposes of this paragraph (l) is the fraction, the numerator of which is the number of Final Closing Purchased Units and the denominator of which is the number of TPC's Units. The purchase price as so determined shall be paid in full as follows:~~

~~(a) if the number of Final Closing Purchased Units is less than the number of TPC's Loan Units, the Final Closing Purchased Units shall be retained by Hydro in full and final satisfaction of: (i) that portion of the Final Closing Date Principal Obligations equal to the Purchase Fraction multiplied by the Final Closing Date Principal Obligations, and the repayment effected thereby shall (to the extent only of the Total Outstandings that are repaid) constitute a permanent reduction of the Equity Credit Facility Commitment; and (ii) that portion of the Final Closing Date Interest Obligations equal to the Interest Purchase Fraction multiplied by the Final Closing Date Interest Obligations;~~

~~(b) if the number of Final Closing Purchased Units is equal to the number of TPC's Loan Units, the Final Closing Purchased Units shall be retained by Hydro in full and final satisfaction of: (i) all of the Final Closing Date Principal Obligations due to Hydro, and Hydro shall fully and finally release and discharge TPC for all of the Final Closing Date Principal Obligations due to Hydro; and the repayment~~

~~effected thereby shall terminate the right of TPC to receive additional Equity Credit Advances; and (ii) that portion of the Final Closing Date Interest Obligations equal to the Interest Purchase Fraction multiplied by the Final Closing Date Interest Obligations.~~

~~(2) If TPC has not complied with Section 2.6(3)(a), and Hydro has exercised its right to purchase all of TPC's Units, the purchase price for the Final Closing Purchased Units to be purchased by Hydro pursuant to the exercise of the Final Closing Purchase Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, and all accrued and unpaid interest, costs and all other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Final Closing Date, and (B) is TPC's Invested Cash as at the Final Closing Date. The purchase price as so determined shall be paid in full by Hydro as follows:~~

~~(a) by Hydro accepting the Final Closing Purchased Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Final Closing Date, and by Hydro fully and finally releasing and discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and~~

~~(b) by Hydro paying to TPC on the effective date of the sale of the Final Closing Purchased Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII, and the payment~~

~~effected thereby shall terminate the Credit Facilities and the Dividend Credit Facility (as defined under the NCN Financing Agreement).~~

~~(3) The purchase price for the Adjustment Purchased Units to be purchased by Hydro pursuant to the exercise of the Adjustment Purchase Right shall be the sum of: (A) the amount determined by multiplying the Purchase Fraction by the Adjustment Date Principal Obligations, where the "Purchase Fraction" for the purposes of this paragraph (3) is the fraction, the numerator of which is the number of Adjustment Purchased Units and the denominator of which is the number of TPC's Loan Units, and the "Adjustment Date Principal Obligations" is the Total Outstandings under this Agreement and the Loan Documents pursuant hereto in respect of the Equity Credit Facility, and all unpaid costs and other amounts due and owing to Hydro under or in respect of the Equity Credit Facility, as at the Time of Adjustment, but not including accrued and unpaid interest; and (B) is the amount determined by multiplying the Interest Purchase Fraction by the Adjustment Date Interest Obligations, where the "Interest Purchase Fraction" for the purposes of this paragraph (3) is the fraction, the numerator of which is the number of Adjustment Purchased Units and the denominator of which is the number of TPC's Units and the "Adjustment Date Interest Obligations" is the accrued and unpaid interest in respect of the Equity Credit Facility, as at the Time of Adjustment. The purchase price as so determined shall be paid in full as follows:~~

~~(a) if the number of Adjustment Purchased Units is less than the number of TPC's Loan Units, the Adjustment Purchased Units shall be retained by Hydro in full and final satisfaction of: (i) that portion of the Adjustment Date Principal Obligations equal to the Purchase Fraction multiplied by the Adjustment Date Principal Obligations, and the repayment effected thereby shall (to the extent only of the Total Outstandings that are repaid) constitute a permanent reduction of the Equity Credit Facility Commitment; and (ii) that portion of the Adjustment Date~~

~~Interest Obligations equal to the Interest Purchase Fraction multiplied by Adjustment Date Interest Obligations; and~~

~~(b) if the number of Adjustment Purchased Units is equal to the number of TPC's Loan Units, the Adjustment Purchased Units shall be retained by Hydro in full and final satisfaction of: (i) all of the Adjustment Date Principal Obligations due to Hydro, and Hydro shall fully and finally release and discharge TPC in writing for all of the Adjustment Date Principal Obligations due to Hydro, and the repayment effected thereby shall terminate the right of TPC to receive additional Equity Credit Advances; and (ii) that portion of the Adjustment Date Interest Obligations equal to the Interest Purchase Fraction multiplied by Adjustment Date Interest Obligations.~~

~~(4) The purchase price for the Non-Completion Purchased Units to be purchased by Hydro pursuant to the exercise of the Non-Completion Purchase Right shall be an amount equal to the sum of (A) and (B), where (A) is the aggregate of the Total Outstandings under the Equity Credit Facility, and all accrued and unpaid interest, costs and all other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Non-Completion Date, and (B) is TPC's Invested Cash as at the Non-Completion Date. The purchase price as so determined shall be paid in full by Hydro as follows:~~

~~(a) by Hydro accepting the Non-Completion Purchased Units in full and final satisfaction of the Total Outstandings due to Hydro under the Equity Credit Facility and of all accrued and unpaid interest, costs and other amounts whatsoever owing by TPC or NCN to Hydro under this Agreement, the NCN Financing Agreement and the Loan Documents pursuant hereto and thereto, as of the Non-Completion Date, and by Hydro fully and finally releasing and~~

~~discharging TPC and NCN for all of the Obligations due to Hydro under this Agreement, the NCN Financing Agreement (the Obligations thereunder being as defined therein) and all Loan Documents hereunder and thereunder; and~~

~~(b) by Hydro paying to TPC on the effective date of the sale of the Non-Completion Purchased Units, an amount in immediately available funds equal to TPC's Invested Cash, without interest, in accordance with Article VII, and the payment effected thereby shall terminate the Credit Facilities and the Dividend Credit Facility (as defined under the NCN Financing Agreement).~~

~~6.3 Exercise of the Final Closing Purchase Right, Adjustment Purchase Right and Non-Completion Purchase Right.~~

~~The Final Closing Purchase Right, the Adjustment Purchase Right and the Non-Completion Purchase Right may only be exercised by giving Notice to TPC in the manner set out in Section 6.4 (the "**Notice of Purchase**"). It shall be a condition of exercise of any of Hydro's rights under Article VI that Hydro comply with the applicable notice requirements of Section 5.3 hereof.~~

~~If TPC has received a Notice of Purchase from Hydro based on the exercise of the Final Closing Purchase Right or the Adjustment Purchase Right and TPC issues a Dispute Notice (as that term is defined in the PDA) within five (5) Business Days of TPC's receipt of the Notice of Purchase which disputes that Hydro is entitled to exercise the Final Closing Purchase Right or Adjustment Purchase Right in the manner that it has been exercised (including, without limitation, on the basis that Hydro applied its discretion improperly or erroneously in denying all or a part of a proposed payment to be made by TPC pursuant to a Credit Facility Repayment Certification or Limited Partnership Payment Certification, and as a result of such alleged error, TPC was not permitted to make the payment to bring itself into compliance with Section 2.6(3) or Section 2.6(4), as applicable) Hydro shall not be entitled to proceed further with the purchase~~

~~of all or any of TPC's Units until such time as the dispute is finally resolved pursuant to Article XXI of the PDA. For greater certainty, no further proceedings shall be taken by Hydro in respect of the Notice of Purchase or in furtherance of the purchase of all or any of TPC's Units, including acting on the power of attorney granted to Hydro pursuant to Section 7.4, until after a final determination is made in accordance with Article XXI of the PDA in respect of the Dispute Notice. Until the aforesaid final determination is made, TPC and Hydro agree that the General Partner shall holdback, in an interest-bearing escrow account, any Distributions that TPC would otherwise be entitled to receive on the Final Closing Purchased Units or Adjustment Purchased Units, and the General Partner shall hold such Distributions in escrow pending the final determination of the Dispute Notice, whereupon the Distributions (and any interest income earned thereon) shall be released in accordance with the direction of the arbitrator appointed pursuant to Article XXI of the PDA.~~

~~6.4 Contents of the Notice of Purchase.~~

~~(1) The Notice of Purchase shall only be effective for the exercise of the Final Closing Purchase Right if it:~~

~~(a) is sent or delivered to TPC after the occurrence of the Final Closing Purchase Option Event which entitles Hydro to exercise the Final Closing Purchase Right;~~

~~(b) indicates that pursuant to Section 6.4(1), Hydro is exercising its right to purchase from TPC the Final Closing Purchased Units;~~

~~(c) specifies the number of TPC's Units that constitute the Final Closing Purchased Units and the purchase price for the Final Closing Purchased Units, calculated in accordance with the provisions of this Agreement;~~

~~(d) is executed by Hydro; and~~

~~(e) is delivered to TPC not more than fourteen (14) calendar days after the Final Closing Date, together with a statement from Hydro confirming:~~

~~(i) that Hydro has elected to purchase the Final Closing Purchased Units pursuant to the Final Closing Purchase Right; and~~

~~(ii) that Hydro is not in default with respect to any material provision of the Loan Documents;~~

~~which statements shall be certified as true and correct in all material respects by a duly authorized officer of Hydro for and on behalf of Hydro.~~

~~(2) The Notice of Purchase shall only be effective for the exercise of the Adjustment Purchase Right if it:~~

~~(a) is sent or delivered to TPC after the occurrence of the Adjustment Purchase Option Event which entitles Hydro to exercise the Adjustment Purchase Right;~~

~~(b) indicates that pursuant to this Section 6.4(2), Hydro is exercising its right to purchase from TPC the Adjustment Purchased Units;~~

~~(c) specifies the number of TPC's Units that constitute the Adjustment Purchased Units and the purchase price for the Adjustment Purchased Units, calculated in accordance with the provisions of this Agreement;~~

~~(d) is executed by Hydro; and~~

~~(e) is delivered to TPC not more than fourteen (14) calendar days after the first Anniversary Date together with a statement from Hydro confirming:~~

~~(i) that Hydro has elected to purchase the Adjustment Purchased Units pursuant to the Adjustment Purchase Right; and~~

~~(ii) that Hydro is not in default with respect to any material provision of the Loan Documents;~~

~~which statements shall be certified as true and correct in all material respects by a duly authorized officer of Hydro for and on behalf of Hydro.~~

~~(3) The Notice of Purchase shall only be effective for the exercise of the Non-Completion Purchase Right if it:~~

~~(a) is sent or delivered to TPC after the occurrence of the Non-Completion Purchase Option Event which entitles Hydro to exercise the Non-Completion Purchase Right;~~

~~(b) indicates that pursuant to Section 6.4(3) Hydro is exercising its right to purchase from TPC the Non-Completion Purchased Units;~~

~~(c) specifies the number of TPC's Units that constitute the Non-Completion Purchased Units and the purchase price for the Non-Completion Purchase Units calculated in accordance with the provisions of this Agreement;~~

~~(d) is executed by Hydro; and~~

~~(e) is delivered to TPC not more than forty (40) calendar days after the Non-Completion Date, together with a statement from Hydro confirming:~~

~~(i) that Hydro has elected to purchase the Non-Completion Purchased Units pursuant to the Non-Completion Purchase Right; and~~

~~(ii) that Hydro is not in default with respect to any material provision of the Loan Documents;~~

~~which statements shall be certified as true and correct in all material respects by a duly authorized officer of Hydro for and on behalf of Hydro.~~

~~**6.5 Effect of the Notice of Purchase and Closing Arrangements.**~~

~~If a Notice of Purchase is sent to TPC in compliance with Section 6.4, then Hydro shall be obligated to purchase the applicable Purchased Units from TPC at the purchase price and in the manner determined in accordance with Section 6.2; and~~

~~(a) TPC shall be obligated to sell the applicable Purchased Units to Hydro at the purchase price and in the manner determined in accordance with Section 6.2; and~~

~~(b) such purchase and sale shall be completed on the date, at the place and in the same manner determined in accordance with the provisions of Article VII.~~

[Intentionally deleted]

ARTICLE VII

GENERAL TERMS AND CONDITIONS APPLICABLE TO ANY SALE

7.1 Application and Terms and Condition.

The following provisions of this Article VII shall apply to any Sale pursuant to Article V ~~or VI hereof.~~ of this Agreement:

(1) Closing Date and Sale.

The Sale shall be completed on the date and at the place determined in accordance with the provisions of this Article VII:

(a) the Sale shall be completed:

~~(i) on the Final Closing Date if the Sale is pursuant to exercise of the Final Closing Sale Right;~~

~~(ii) on the date that is twenty-eight (28) calendar days after the Final Closing Date if the Sale is pursuant to the exercise of the Final Closing Purchase Right;~~

~~(iii) on the date that is twenty-eight (28) calendar days after the first Anniversary Date if the Sale is pursuant to the exercise of the Adjustment Purchase Right;~~

~~(iv) on the date that is twenty-eight (28) calendar days after the Notice of Sale is issued if the Sale is pursuant to the exercise of the Non-Completion Sale Right;~~

~~(v) on the date that is twenty-eight (28) calendar days after the Notice of Purchase is issued if the Sale is pursuant to the exercise of the Non-Completion Sale Right;~~

~~(vi)~~ (i) on the twenty-fifth Anniversary Date if the Sale is pursuant to the exercise of the Twenty-Fifth Anniversary Sale Right;

~~(vii) on~~(ii) the Maturity Date if the Sale is pursuant to the exercise of the Maturity Date Sale Right;

~~(viii) On~~(iii) on the date that is twenty-eight (28) calendar days after the Notice of Sale is issued if the Sale is pursuant to the exercise of the Term Sale Right;

as the case may be, provided, however, that the said Sale may occur on such other date that the parties may mutually agree upon (the "**Sale Closing Date**"); and

(b) the place for the completion of the Sale shall be the head office of Hydro in connection with the Sale or if applicable the law office of the external legal counsel of Hydro or such other place as the parties may mutually agree upon.

(2) Sale Closing Arrangements.

At or before the Sale Closing Date, TPC shall deliver the following to Hydro subject to Hydro complying with all required conditions on Hydro as set out in this Article VII, including payment to TPC in full of the purchase price for the Sale Units or ~~Purchased Units (as applicable)~~:

(a) one or more certificates representing in the aggregate the Sale Units~~ or Purchased Units (as applicable)~~, duly endorsed in blank for transfer to Hydro (the "**Sale Certificate(s)**") or power of attorney appointing Hydro as attorney of TPC to transfer the Sale Units~~ or Purchase Units (as applicable)~~ to Hydro, provided that where the number of Units represented by the Sale Certificate(s) exceed the number of Sale Units ~~or Purchased Units (as applicable), ~~the transfer of the Sale Units ~~or Purchased Units (as applicable) ~~to Hydro shall be conditional upon Hydro's receipt from the Limited Partnership of a replacement certificate, (unless the Equity Credit ~~Facilities~~Facility under this Agreement have been terminated and the Dividend Credit Facility, as that term is defined under the NCN Financing Agreement, has been terminated and there are no outstanding Obligations under this Agreement or under the NCN Financing Agreement, as defined under that agreement, in which event the said certificate shall be forwarded to TPC), confirming TPC's ownership of that number of Units which is in excess of the number of Sale Units~~ or Purchased Units (as applicable)~~. Hydro is authorized to retain the replacement certificate(s) for such period of time as there are any outstanding Obligations under this Agreement or under the NCN Financing Agreement (as defined under that agreement) and Hydro agrees to provide copies to TPC of all of the said certificates, together with confirmation in writing that it is holding the originals of the said certificates immediately upon receipt thereof;

(b) such other documents as Hydro may reasonably require to entitle Hydro to require the General Partner to register the transfer of such Sale Units~~ or Purchased Units, (as applicable),~~ to Hydro and to entitle Hydro to become the registered holder of such Sale Units~~ or Purchased Units (as applicable)~~ on the books of the Limited Partnership, free and clear of all Liens except the Permitted Liens (the particulars of which have been identified in writing to Hydro to the extent that TPC is aware of the existence of such Permitted Liens) and such other Liens as at the Sale Closing Date as Hydro may, in its unfettered discretion, accept in writing;

(c) a certificate bearing the date on which the Sale Closing Date occurs wherein TPC certifies~~:~~

~~(i)~~ in respect of the Sale Units ~~(if applicable)~~ as being true and correct, each of the ~~Final Closing Sale Conditions, the Non-Completion Sale Conditions,~~ Term Sale Conditions, the Twenty-Fifth Anniversary Sale Conditions, or the Maturity Sale Conditions, as applicable, as at the Sale Closing Date; and

~~(ii) in respect of the Purchased Units (if applicable) that TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of the Purchased Units free and clear of all Liens except the Permitted Liens (the particulars of which have been identified in writing to Hydro to the extent that TPC is aware of the existence of such Permitted Liens) and such other Liens as at the Sale Closing Date as Hydro may, in its unfettered discretion, accept in writing, that TPC has the full right to sell and transfer the Purchased Units to Hydro and that no person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Purchased Units other than Hydro; and~~

(d) a certificate bearing the closing date wherein TPC certifies, as being true, as at the Sale Closing Date a statement to the effect that on such date TPC is resident in Canada for the purposes of the *Income Tax Act*.

(3) Title and other TPC Covenants.

At the Sale Closing Date, TPC shall transfer and deliver to Hydro good and marketable title to such Sale Units~~ or Purchased Units (as applicable),~~ free and clear of all Liens except for the Permitted Liens (the particulars of which have been identified in writing to Hydro to the extent that TPC is aware of the existence of such Permitted Liens) and any -other Liens that Hydro, in its unfettered discretion, agrees in writing at the Sale Closing Date that the Sale~~ or Purchased Units (as applicable)~~ may be subject to.

(4) Satisfaction of Purchase Price.

At the Sale Closing Date, Hydro shall satisfy the purchase price for the Sale Units ~~or Purchased Units (as applicable),~~ to be purchased from TPC in the manner provided for in this Agreement, and in the event that the Sale Units~~ or Purchased Units (as applicable)~~ constitute all of TPC's Units, Hydro shall arrange for discharge of all registrations in public registries made against TPC and/or NCN under the Security Documents pursuant to this Agreement and under the Security Documents pursuant to the NCN Financing Agreement (and the original Guarantee, as defined under the NCN Financing Agreement, shall be returned to TPC for cancellation).

7.2 Conditions to the Obligations of Hydro.

Notwithstanding anything ~~herein contained~~in this Agreement, , the obligations of Hydro to complete the Sale of the Sale Units ~~or Purchased Units (as applicable)~~, shall, until the Sale has been completed, be subject to the fulfillment of the following conditions and TPC covenants and agrees to perform and comply with each and ~~everyone~~every one of such conditions insofar as such conditions relate to matters within the control of TPC:

(1) all terms, covenants, agreements and conditions of this Agreement which are to be complied with or performed by TPC at or before the Sale Closing Date shall have been complied with and performed in all material respects in accordance with the terms of this Agreement prior to or at such time; and

(2) at the Sale Closing Date, TPC shall, without limitation to all other obligations of TPC in respect of the Sale as set out in this Agreement execute and deliver to Hydro a certificate bearing the Sale Closing Date wherein a duly authorized officer of TPC shall certify as true, for and on behalf of TPC (and not in such officer's personal capacity), a statement to the effect that at such time the conditions set out in paragraph (1) above have been performed, complied with and fulfilled except as specifically disclosed in such certificate and the closing of the Sale shall not be effective unless and until Hydro accepts in writing any and all exceptions disclosed in such certificate.

The conditions applicable to a Sale of the Sale Units~~ or Purchased Units (as applicable)~~, contained in the ~~foregoing~~ provisions of this Section 7.2 are inserted for the exclusive benefit of Hydro ~~in respect of the Sale of the Sale Units or Purchased Units (as applicable)~~ and may be waived in whole or in part by Hydro at any time without prejudice to the right of Hydro to rely on all covenants and agreements and representations and warranties in this Agreement and all conditions contained in this Section 7.2, except to the extent that Hydro has in writing waived its right to rely on such covenants, agreements, representations, warranties or conditions. If any of the conditions applicable to a Sale of the Sale ~~Units or Purchased Units (as applicable), and~~ contained in this Section 7.2 ~~hereof shall~~ are not be fulfilled or complied with as herein provided, Hydro may, at its option:

(a) terminate the obligations of TPC and Hydro in respect of the Sale of the Sale Units~~ or Purchased Units, (as applicable)~~ by notice in writing to TPC and in such event Hydro and TPC shall be released from all obligations hereunder in respect of the Sale of the Sale Units ~~or Purchased Units (as applicable);~~

(b) defer the completion of the Sale of the Sale Units ~~or Purchased Units, (as applicable)~~ to a new closing date (not to exceed three (3) months after the original closing date except by agreement in writing of the parties) to determine if the aforesaid conditions can be fulfilled or complied with; or

(c) bring an action for specific performance or any other remedy which may be available to Hydro.

7.3 Conditions to the Obligations of TPC.

Notwithstanding anything herein contained, the obligations of TPC to complete the Sale of the Sale Units ~~or Purchased Units, as applicable,~~ shall, until the Sale has been completed, be subject to the fulfillment of the following conditions and Hydro covenants and agrees to perform and comply with each and every one of such conditions insofar as such conditions relate to matters within the control of Hydro:

(1) all terms, covenants, agreements and conditions of this Agreement which are to be complied with or performed by Hydro at or before the Sale Closing Date shall have been complied with and performed in all material respects in accordance with the terms of this Agreement prior to or at such time; and

(2) at the Sale Closing Date, Hydro shall, without limitation to all other obligations of Hydro in respect of the Sale as set out in this Agreement, execute and deliver to TPC a certificate bearing the Sale Closing Date wherein a duly authorized officer of Hydro shall certify as true, for and on behalf of Hydro (and not in such officer's personal capacity), a statement to the effect that the conditions set out in

paragraph (1) above have been performed, complied with and fulfilled except as specifically disclosed in such certificate (and the closing of the Sale shall not be effective unless and until TPC accepts in writing any and all exceptions disclosed in such certificate).

The conditions applicable to a Sale of the Sale Units~~ or Purchased Units (as applicable)~~ contained in the foregoing provisions of this Section 7.3 are inserted for the exclusive benefit of TPC in respect of the Sale of the Sale Units~~ or the Purchased Units (as applicable),~~ and may be waived in whole or in part by TPC at any time without prejudice to the right of TPC to rely on all covenants and agreements and representations and warranties in this Agreement and all conditions contained in this Section 7.3 except to the extent that TPC has in writing waived its right to rely on such covenants, agreements, representations, warranties or conditions. If any of the conditions applicable to a Sale of the Sale Units~~ or the Purchased Units (as applicable),~~ and contained in this Section 7.3 shall not be fulfilled or complied with as herein provided, TPC may, at its option:

(a) terminate the obligations of Hydro and TPC in respect of the sale of the Sale Units~~ or the Purchased Units, (as applicable)~~ by notice in writing to Hydro and in such event TPC and Hydro shall be released from all obligations hereunder in respect of the Sale of the Sale Units~~ or Purchased Units~~;

(b) defer the completion of the Sale of the Sale Units~~ or the Purchased Units, (as applicable)~~ to a new closing date (not to exceed three (3) months after the original closing date except by agreement in writing of the parties, to determine if the aforesaid conditions can be fulfilled or complied with; or

(c) bring an action for damages or specific performance or any other remedy which may be available to TPC.

7.4 Power of Attorney.

Subject to payment of the purchase price to TPC and subject to Section- 6.3 hereof, TPC hereby irrevocably nominates, constitutes and appoints Hydro, its attorney and agent, for, in the name of and on behalf of TPC to do all acts and things and sign all documents (other than any releases of Hydro, the General Partner or the Limited Partnership) which are necessary or desirable to complete the Sale of the Sale Units~~ or Purchased Units (as applicable)~~ by TPC to perform, satisfy or discharge any obligations in relation to the Sale of the Sale Units or Purchased Units (as applicable) by TPC in connection with a Sale and, without limiting the foregoing, TPC acknowledges and agrees that Hydro is hereby granted authority to receive and accept delivery of and keep possession of, and to execute and deliver, in the name of and on behalf of TPC all such certificates, instruments and documents as may be necessary or desirable, (other than any releases of Hydro, the General Partner or the Limited Partnership) in the opinion of Hydro, acting reasonably, to complete any Sale of the Sale Units~~ or Purchased Units (as applicable),~~ or to perform, satisfy or discharge any obligations in relation to a Sale of the Sale Units ~~or the Purchased Units, (as applicable)~~. TPC hereby acknowledges and agrees that the appointment hereby made and the powers hereby granted are coupled with an interest and are and shall be irrevocable and to the extent permitted by applicable Laws shall survive the dissolution, insolvency or bankruptcy of TPC and may be exercised by Hydro in its own name or in the name of TPC and shall survive any assignment or purported assignment of TPC's Units by TPC and to the extent permitted by applicable laws, shall be binding upon the successors and permitted assigns of TPC.

If Hydro, as attorney on behalf of TPC completes the Sale of the Sale Units~~ or Purchased Units, (as applicable),~~ Hydro shall be entitled to have any proceeds of the Sale, to which TPC would otherwise be entitled to receive, paid to legal counsel for Hydro (as designated by Hydro) to be held in trust for TPC, and to be retained by such legal counsel until TPC delivers to Hydro such documents as TPC is required to deliver under this Agreement to complete the Sale of the Sale Units~~ or the Purchased Units (as applicable)~~. Promptly upon the receipt of such documents by Hydro, Hydro's legal counsel shall pay the applicable proceeds, and deliver any other applicable closing documents to which TPC is entitled, to TPC, together with such interest as legal counsel may have earned on such proceeds.

ARTICLE VIII

~~CONDITIONS OF LENDING~~

~~8.1 Conditions Precedent to Initial Advances~~

~~The obligation of Hydro to make Advances:~~

~~(a) under the Equity Credit Facility commencing on the Initial Closing Date; and~~

~~(b) under the Cash Call Credit Facility commencing after the Final Closing Date;~~

~~are subject to the following conditions to be fulfilled or performed at or prior to Initial Closing Date, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro:~~

~~(1) **Deliveries**. Hydro shall have received, at or prior to the time of the making of any Advances on the Initial Closing Date, the following, each dated such day as is satisfactory to Hydro:~~

~~(a) certified copies of: (i) constating documents and by-laws of TPC; and (ii) resolutions of the board of directors of TPC approving the entering into of this Agreement and each of the other Loan Documents by TPC and the completion of all transactions contemplated hereunder and thereunder;~~

~~(b) certificate of the secretary of TPC certifying the names and true signatures of the Persons authorized to sign this Agreement and each of the other Loan Documents on behalf of TPC;~~

~~(c) certificate of status with respect to TPC;~~

~~(d) this Agreement, duly executed and delivered as required by TPC;~~

~~(e) the Security Documents creating a first charge security interest on TPC's Units and the Distributions on TPC's Units, in form and substance satisfactory to Hydro, acting reasonably;~~

~~(f) original certificate(s) for TPC's Units, together with duly executed power of attorney in respect of TPC's Units (to be held by Hydro pursuant to the terms of the Security Documents), together with an irrevocable direction from TPC, directing and authorizing the General Partner that all certificates for any TPC's Units issued subsequent to Initial Closing, shall not be forwarded to TPC but shall immediately be forwarded directly to Hydro (to be held by Hydro pursuant to the terms of the Security Documents). All original certificates shall be returned to TPC after the Credit Facilities under this Agreement have been terminated and the Dividend Credit Facility (as that term is defined in the NCN Financing Agreement) has been terminated and there are no outstanding Obligations under this Agreement or under the NCN Financing Agreement (as defined in that Agreement);~~

~~(g) evidence of the registration of the Security Documents in all offices where such registration, filing or recording is necessary or desirable to protect any rights or remedies of Hydro thereunder and receipt of legal opinions of registration counsel in form and substance acceptable to Hydro, provided however that Hydro shall~~

~~use its commercially reasonable efforts to complete all such registrations and to obtain the required evidence and opinions from its legal counsel in advance of the Initial Closing Date;~~

~~(h) legal opinions of counsel to TPC confirming the due authorization, execution and, delivery of this Agreement and each of the other Loan Documents to which TPC is a party subject to the customary qualifications and assumptions for such opinions (but, for greater certainty, no opinions as to enforceability will be required from legal counsel to TPC);~~

~~(i) a copy of each Material Agreement, which shall each be in form and substance acceptable to Hydro, in its discretion, acting reasonably;~~

~~(j) duly completed Schedules C, D and E to this Agreement in form and substance satisfactory to Hydro, acting reasonably; and~~

~~(k) such other certificates and documentation as Hydro may reasonably request to give effect to this Agreement.~~

~~(2)~~ ~~**No Material Adverse Business Effect**. No event, condition or circumstance has arisen which would have a Material Adverse Business Effect.~~

~~(3)~~ ~~**Due Diligence.** Hydro shall have completed its due diligence in respect of TPC and the Material Agreements, and shall be satisfied with the results of such due diligence, in its sole discretion.~~

~~(4)~~ ~~**Authorizations.** Hydro has received all Authorizations that it requires for the due performance of the Loan Documents (which Authorizations are as specified in~~

~~Schedule H) with the sole exception that Hydro will require additional borrowing authority from Manitoba under applicable legislation for amounts to be borrowed by Hydro after August 31, 2006, to fund Advances requisitioned by TPC by Borrowing Notices thereafter (the "**Additional Borrowing Authorizations**"). Hydro covenants and agrees to use its best efforts to obtain such Additional Borrowing Authorizations as may be required by it from time to time for the due and timely performance of its covenants under the Loan Documents.~~

~~(5) **PDA**. All of the conditions set forth in Article XIII of the PDA have been fulfilled or performed.~~

~~(6) **TPC's Cash Subscription Payment.** TPC's Cash Subscription Payment must be a minimum amount of $1,000,000.~~

~~(7) **Other Conditions.** The conditions set forth in Section 8.2 shall have been fulfilled or performed.~~

~~**8.2 Additional Conditions Precedent to Initial Advance.**~~

~~The obligation of Hydro to make Advances under the Credit Facilities is subject to the following conditions to be fulfilled or performed at or prior to the Final Closing Date, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro:~~

~~(1) **PDA.** All of NCN's and TPC's obligations to be performed or fulfilled on or before the Final Closing Date pursuant to the PDA have been fulfilled or~~

~~performed and NCN and TPC are in compliance with all of the provisions of the PDA.~~

~~(2) **NCN Financing Agreement.** All of NCN's and TPC's obligations to be performed or fulfilled on or before the Final Closing Date pursuant to the provisions of the NCN Financing Agreement have been fulfilled or performed, and NCN and TPC are in compliance with all of the provisions of the NCN Financing Agreement.~~

~~**8.3 Conditions of all Advances.**~~

~~At any time, the obligation of Hydro to make an Advance shall be subject to the following conditions being satisfied on the date of such Advance, which conditions are for the exclusive benefit of Hydro and may be waived in whole or in part by Hydro, in its sole discretion:~~

~~(1) **Credit Facility Commitment Limits**. The Total Outstandings under the Credit Facility in respect of which the Advance is requested in the Borrowing Notice shall not, prior to or after giving effect to the Advance, exceed the Credit Facility Commitment for such Credit Facility.~~

~~(2) **Truth of Representations and Warranties**. The representations and warranties of TPC contained in this Agreement and in any other Loan Document to which TPC is a party, shall be true and correct as of the date on which such Advance is made with the same force and effect as if such representations and warranties had been made on and as of such date; provided that, to the extent the disclosure in the representations and warranties is no longer true and correct, TPC shall be entitled~~

~~to update such disclosure to Hydro, and if such disclosure is not materially adverse, it must be approved by Hydro.~~

~~(3) **Performance of Covenants**. TPC shall have fulfilled or complied with all covenants herein contained or contained in any other Loan Document to be performed or caused to be performed by it at or prior to the date of such Advance.~~

~~(4) **No Event of Default**. No Event of Default shall have occurred and be continuing.~~

~~(5) **Authorizations**. Hydro has obtained such borrowing authority (including the Additional Borrowing Authorizations) as may be required by it from time to time for the due and timely performance of its covenants under the Loan Documents, including in order to enable it to make the Advances requisitioned from time to time by TPC by Borrowing Notices.~~

~~(6) **No Change in Laws**. No Law or change in any Law shall have been introduced or enacted, the effect of which will be to prohibit Hydro from making any Advance.~~

~~(7) **Limited Partnership.** TPC is a limited partner in the Limited Partnership.~~

~~(8) **Borrowing Notice**. Hydro shall have received a Borrowing Notice in compliance with this Agreement.~~

[Intentionally deleted.]

ARTICLE IX
REPRESENTATIONS AND WARRANTIES.

9.1 Representations and Warranties.

To induce Hydro to make Advances available ~~hereunder~~under this Agreement, TPC represents and warrants to Hydro that each of the following representations and warranties is true and correct:

~~(1)~~ (1) Status and Power. TPC is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has full corporate power and capacity to own its property and carry on its Business. TPC is duly qualified, licenced or registered to carry on business in Manitoba.

~~(2)~~ (2) Authorization. TPC has full power and capacity and full legal right to enter into and perform its obligation under this Agreement and each of the other Loan Documents to which it is or will be a party, and has or will have by the Initial Closing Date taken all action necessary to be taken by it to authorize such acts.

~~(3)~~ (3) Enforceability of Agreement. This Agreement and any other Loan Document to which TPC is a party constitutes legal, valid and binding obligations of TPC enforceable against it in accordance with their respective terms, subject only to any limitation under applicable Laws relating to (a) bankruptcy, insolvency, reorganization, moratorium or creditors' rights generally; and (b) the discretion that a court, or an arbitrator duly appointed under Article XXI of the PDA, may exercise in the granting of equitable remedies.

~~(4)~~ (4) Government Approval and Regulation. No Authorization or approval or other action by, and no notice to or filing with, any Governmental Entity or other Person (other than those that have been, or by the Initial Closing Date will be, duly obtained or made) is required for the due execution, delivery or performance by TPC of any Loan Document to which TPC is a party.

~~(5)~~ (5) Litigation. There is no material action, suit or proceeding which has been commenced (Notice of which has been served on TPC), or to the best of the knowledge of TPC, pending or threatened against TPC before or by any Governmental Entity, or before any arbitrator or board, which would prevent TPC from performing its obligations under any of the Loan Documents to which it is a party. TPC is not in default with respect to any judgment, order, writ, injunction, decree, or award of any court, arbitrator, board or other Governmental Entity, nor is there any judgment, order, writ, injunction, decree, or award which would prevent TPC from performing its obligations under any of the Loan Documents to which it is a party.

~~(6)~~ (6) Imposition of Lien. The consummation of the transactions hereby contemplated and the compliance with the terms, conditions and provisions of this Agreement and each of the other Loan Documents will not result in the creation or imposition of any Lien on any Property of TPC except as otherwise permitted by this Agreement.

~~(7)~~ (7) No Other Material Facts. None of:

~~(a)~~ (a) this Agreement;

~~(b)~~ (b) any of the other Loan Documents; or

~~(c)~~ (c) any certificate or statement in writing which has been supplied by or on behalf of TPC and is a document that is required to be delivered to Hydro pursuant to the provisions of the Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

~~(8)~~ (8) Restrictive Documents. TPC is not subject to, or a party to, any restriction in its constating documents or by-laws, any Notice, any Law, any Claim, any contract or instrument, any Lien, or any other restriction of any kind or character which would prevent the consummation of the transactions contemplated by this Agreement or any other Loan Documents or compliance by TPC with the terms, conditions and provisions hereof or thereof or the continuing operation of the Business.

~~(9)~~ (9) Title to Property. TPC is the registered owner and sole beneficial owner of and has good and marketable title to and is lawfully possessed of its Property free and clear of all Liens, except Permitted Liens. TPC has full right to mortgage, pledge, charge and assign to Hydro the Collateral. No Person has any written or oral agreement, option, understanding or commitment, or any right or privilege capable of becoming any agreement, option, understanding, commitment or right for the purchase from TPC of the Collateral other than Hydro.

~~(10)~~ (10) Compliance with Laws. TPC is in material compliance with all applicable Laws.

~~(11)~~ (11) No Breach of Contracts. Schedule D will be completed and provided by TPC to Hydro on or before the Initial Closing Date, and will, upon completion and deliver thereof, contain a complete and accurate list of all agreements to which TPC is a party in connection with the Corporate Distributions of TPC, the Capital Stock of TPC, the equity interest that NCN has in TPC, TPC's Units and Distributions on TPC's Units, and any other agreement to which TPC is a party creating liabilities or obligations upon any Person over the term of the agreement in excess of $75,000, or is otherwise material to TPC (collectively, the "Material Agreements"). TPC has provided, or will on or before the Initial Closing Date provide, copies of all of the Material Agreements, including amendments, or additions thereto, to Hydro. On the date of execution of each of the Future Material Agreements (as defined below in Section 10.1(14)), Schedule D hereto shall be deemed to be amended to include such Future Material Agreements and such Future Material Agreements shall be deemed to be "Material Agreements" for the purposes of this Agreement from and after such execution date, without the necessity of any further action by any of the parties hereto. Each Material Agreement is, or will on before Initial Closing Date be, in full force and effect, unamended (except as disclosed to Hydro), and there exists no default, or event, occurrence, condition or act (including the completion of the transactions contemplated in this Agreement and the other Loan Documents) which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become a default thereunder. TPC has not violated or breached, in any respect, any of the terms or conditions of any Material Agreements and, to the best of the knowledge of TPC, all the material covenants to be performed by any other party thereto have been performed in all material respects.

~~(12)~~ (12) Books and Records. All books and records of TPC have been fully, properly and accurately kept and completed in accordance with GAAP and there are no material inaccuracies or discrepancies of any kind contained or reflected therein.

~~(13)~~ (13) Tax Liability. Except for any Taxes which are being diligently contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books:

~~(a)~~ (a) TPC has in a timely manner filed all tax returns, elections, filings and reports with respect to Taxes required by Law to be filed by it and such returns, elections, filings and reports are true, complete and correct;

~~(b)~~ (b) TPC has paid, or reserved in its financial statements, all Taxes which are due and payable, and has paid all assessments and reassessments and all other Taxes, governmental charges penalties, interest and fines due and payable by it;

~~(c)~~ (c) TPC has no liability, contingent or otherwise, for Taxes, except Taxes not now due and payable with respect to ordinary operations during the current fiscal period adequate provision for the payment of which has been made; and

~~(d)~~ (d) TPC has paid as and when due all applicable Taxes and remitted as required by Law all applicable Taxes and deductions and any interest or penalties related thereto.

~~(14)~~ (14) Shareholder. NCN is the beneficial owner of all of the Capital Stock of TPC free and clear of all Liens expect Permitted Liens. The Capital Stock of TPC is owned by the Chief or a Councillor of NCN, as bare trustee for NCN. No Person has any written or oral agreement, option, understanding or commitment or any right capable of becoming any agreement, option, understanding, commitment, or right for purchase of any of the Capital Stock of TPC or to receive payment based on the value of any such Capital Stock. The issued and outstanding Capital Stock and Debt (excluding Debt under this Agreement) of TPC and the registered and beneficial holders of such Capital Stock and Debt (excluding Debt under this

Agreement) are, or will upon completion of delivery of Schedule C be, as described in Schedule C, which will be completed and provided by TPC to Hydro on or before the Initial Closing Date. Hydro acknowledges that the NCN Deed of Assignment shall not be deemed to be a breach of this representation.

~~(15)~~ (15) Liabilities. TPC does not have any liabilities, whether accrued, absolute, contingent or otherwise, of any kind or nature whatsoever, except as otherwise disclosed in Schedule E, which will be completed and provided by TPC to Hydro on or before the Initial Closing Date or pursuant to the Loan Documents, and except incurred after the date hereof in compliance with this Agreement and the Loan Documents.

~~(16)~~ (16) No Event of Default. No Event of Default has occurred, nor has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute an Event of Default under the Loan Documents. No default has occurred not has any event or condition occurred which, with the giving of Notice or passage of time, or both, would constitute a default under any one or more Material Agreements which could result in the acceleration of amounts owing by TPC under any such Material Agreements.

~~(17)~~ (17) Financial Information. The financial statements of TPC furnished to Hydro pursuant to this Agreement have been prepared in accordance with GAAP consistently applied, and present fairly the financial portion of TPC as at the dates thereof and the results of TPC's operations for the periods then ended. All balance sheets, all statements of operations, shareholders' equity and cash flow and all other financial information of TPC furnished pursuant to Section 10.1(1) have been and will for periods following the Initial Closing be prepared in accordance with GAAP, consistently applied, and do or will present fairly the consolidated financial position of TPC as at the dates thereof and the results of their operations for the periods then ended.

~~(18)~~ (18) Resident of Canada. TPC is a resident of Canada for the purposes of the Income Tax Act (Canada).

Each of the representations and warranties contained in this Section 9.1 shall be deemed to be continually repeated by TPC at the time of each Advance.

9.2 ~~9.2~~ Survival of Representations and Warranties.

All the representations and warranties of TPC contained in Section 9.1 of this Agreement shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Equity Credit ~~Facilities have~~Facility has been terminated notwithstanding any investigation made at any time by or on behalf of Hydro.

9.3 Representations by Hydro.

To induce TPC to enter into this Agreement, Hydro represents and warrants to TPC that each of the following representations and warranties is true and correct:

(1) Hydro is a corporation duly incorporated and organized and validly subsisting under the Laws of Manitoba and has the corporate power and authority to own or lease its property and to enter into this Agreement and each of the other Loan Documents to which it is a party and to perform its obligations hereunder and thereunder.

(2) This Agreement and the Loan Documents to which Hydro is a party have been duly authorized, executed and delivered by Hydro and are legal, valid and binding obligations of Hydro, enforceable against Hydro by TPC to the extent that TPC is

a party thereto, in accordance with their terms, except as enforcement may be limited by bankruptcy, insolvency and other Laws affecting the rights of creditors generally, and except that equitable remedies may be granted only in the discretion of a court of competent jurisdiction, or, by this Agreement, at the discretion of the arbitrator.

(3) Subject only to obtaining the Authorizations described in Schedule H, the execution and delivery of this Agreement and each of the Loan Documents to which Hydro is a party and the consummation the transactions herein provided for by Hydro will not result in:

(a) the breach or violation of any other provisions of or constitute a default under or conflict with or cause the acceleration of any obligation of Hydro under:

(i) any contract to which Hydro is a party or by which it, or any of its property, is bound;

(ii) any provision of the constating documents, by-laws or resolutions of the Board of Directors (or any committee thereof) or shareholders of Hydro;

(iii) any judgment, decree, order or award of any court, governmental body or arbitrator having jurisdiction over Hydro; or

(iv) any applicable law, statue, ordinance, regulation or rule, including, without limitation, the *Hydro Act*; or

(b) the creation or imposition of any Lien on any investment transaction or any of the property or assets of Hydro;

(4) Hydro is a resident of Canada for the purposes of the Income Tax Act (Canada).

(5) None of:

(a) this Agreement;

(b) any of the Loan Documents; or

(c) any certificate or statement in writing which has been supplied by or on behalf of Hydro and is a document that is required to be delivered to TPC pursuant to the provisions of this Agreement or any of the other Loan Documents;

contains any untrue statement of a material fact, or omits any statement of a material fact necessary in order to make the statements contained herein or therein not misleading.

(6) There is no requirement for Hydro to make any filing with, give any notice to or obtain any license, permit, certificate, registration, authorization, consent or approval of any government regulatory authority as a condition to the lawful consummation by Hydro of the transaction contemplated by this Agreement and each other Loan Document to which it is a party, except as described in Schedule H.

Each of the representations and warranties contained in this Section 9.3 shall be deemed to be continually repeated by Hydro at the time of each Advance.

9.4 ~~9.4~~ Survival of Representations and Warranties.

All the representations and warranties of Hydro contained in this Article IX shall survive the execution and delivery of this Agreement and shall continue in full force and effect until all amounts owing hereunder have been repaid and the Equity Credit ~~Facilities~~Facility have been terminated notwithstanding any investigation made at any time by or on behalf of TPC.

ARTICLE X
COVENANTS OF TPC

10.1 Affirmative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has ~~any~~the Equity Credit Facility Commitment under this Agreement, and unless Hydro shall otherwise consent, TPC shall:

~~(1) **Financial Reporting and Deliveries**. Cause to be delivered to Hydro the following documents:~~

~~Annual Financial Statements~~

(1) ~~(a)~~ **Financial Reporting and Deliveries**. Cause to be delivered to Hydro as soon as available, and in any event within one hundred and twenty (120) days after the end of each Financial Year, the audited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC for such Financial Year, in accordance with GAAP and subject to an unqualified opinion of the Auditors;

~~Quarterly Financial Statements~~

~~(b) as soon as available, and in any event within sixty (60) days after the end of each Financial Quarter (excluding the last Financial Quarter of a Financial Year), the unaudited financial statements (including, at a minimum, a balance sheet, income statement and statement of changes in financial position) of TPC, prepared in accordance with GAAP.~~

(2) **Additional Reporting and Deliveries**. Cause to be delivered to Hydro, following documents, in form and substance satisfactory to Hydro, acting reasonably:

(a) a copy of each management letter or report submitted to the board of directors (or any committee thereof) or senior management of any of TPC by the Auditors in connection with any annual, interim or special audit made by them of the books of TPC, together with the related response of TPC to be delivered promptly upon the issuance of the response by TPC;

(b) promptly after the occurrence of each Event of Default, a statement of TPC setting forth the details of such Event of Default and the action which TPC proposes to take or have taken with respect thereto;

(c) promptly after the commencement thereof, Notice of Claims which have been commenced against TPC (notice of which has been served on TPC, or to the best of the knowledge of TPC, have been commenced or are pending or threatened against TPC, for amounts which exceed $75,000 in the aggregate at any time or affect any of the Collateral;

(d) promptly after the occurrence of any material development with respect to any Claims referred to in Section 10.1(2)(c), and in any event within three (3) Business Days after TPC obtains knowledge of the occurrence thereof, Notice thereof to Hydro, and, to the extent Hydro requests them, copies of all documentation relating thereto; and

(e) such other information and reports relating to TPC, the Collateral or the Business, as Hydro may from time to time reasonably request.

(3) **Corporate Existence**. Preserve and maintain TPC's corporate existence.

(4) **Compliance with Laws**. Comply, in all material respects, with the requirements of all applicable Laws.

(5) **Payment of Taxes, Claims and Governmental Licence Fees**. Pay and discharge, before the same shall become delinquent:

(a) all Taxes, governmental assessments, charges or levies and Claims imposed upon it or upon any of its Property;

(b) all lawful Claims which, if unpaid, might by Law become a Lien upon its Property, in each case except for any such Tax, assessment, charge, levy or Claim which would result in a Lien which is a Permitted Lien; and

(c) all fees payable to Governmental Entities or other authorities in connection with all governmental licences issued to and held by TPC, (if any).

(6) **Keeping of Books**. Keep proper books, records and accounts, in which full and correct entries shall be made of all of TPC's financial transactions in accordance with GAAP.

(7) **Visitation and Inspection**. If, in the reasonable opinion of Hydro, an Event of Default has or may have occurred, at any reasonable time or times and upon reasonable prior notice given to TPC by Hydro permit Hydro or any of its authorized representatives, full and reasonable access to the premises of TPC and obtain any consents and waivers from any Person necessary, in the reasonable opinion of Hydro to ensure such access, for the purposes of inspecting (and, where required, taking copies of) the business, financial and computer records of TPC and to discuss the business, affairs, finances and accounts of, and the compliance by TPC with the terms of this Agreement and the other Loan Documents with the management and Auditors thereof.

(8) **Protect Hydro Liens**. At all times take all action and supply Hydro with all such information reasonably necessary to allow Hydro to create, maintain, perfect, protect and preserve the Liens provided for under the Security Documents and confer upon Hydro the security interest intended to be created thereby.

(9) **Payments**. Subject to Section 3.7(3), pay all amounts of principal, interest, costs and expenses on the dates, at the times and at the places specified in this Agreement or under any other Loan Document, but subject to the provisions of Section 12.2 in respect of costs and expenses.

(10) **Use of Proceeds.** Apply the proceeds of the Equity Credit ~~Facilities~~Facility only in accordance with Sections 2.4 and 3.4.

(11) **Payment of Preferred Claims**. Pay, as and when due, any and all amounts which may result in a Lien on the Collateral under applicable Law (other than a Permitted Lien), whether or not such Lien is entitled to priority over the Liens in favour of Hydro under the Security Documents.

(12) **Loan Documents.** Execute and deliver to Hydro the Loan Documents.

(13) **Material Agreements**. Comply with the provisions of all of the Materials Agreements. In respect of each Material Agreement executed by TPC after the date hereof (each a "**Future Material Agreement**"), provide to Hydro a certified true copy of each Future Material Agreement.

(14) **Notice of Defaults.** TPC shall immediately notify Hydro:

(a) of any Event of Default or of any event, occurrence, condition or act which, with the giving of Notice, the lapse of time or the happening of any other event or condition, would become an Event of Default, or of any material default (either by TPC or by any other party) under any Material Agreement or of any event which, with the giving of notice, the lapse of time or the happening of any other event or condition, would become a material default under or would otherwise allow the termination of any Material Agreement, and thereafter provide Hydro with all information reasonably requested by Hydro from time to time concerning the status thereof;

(b) on becoming aware of the occurrence of any litigation, dispute, arbitration, proceeding, labour or industrial dispute, the result of which if determined adversely would have a Material Adverse Business Effect on the ability of TPC to perform its obligations under this Agreement and the other Loan Documents, and thereafter provide Hydro with all information reasonably requested by Hydro concerning the status thereof.

(15) **Changes in Year End or Auditors.** TPC shall provide prior notice to Hydro of any changes in its Financial Year end or its auditors, specifying the new Financial Year end or auditors, as the case may be;

(16) ~~(15)~~ **Further Assurances**. Upon request of Hydro, acting reasonably, duly execute and deliver or cause to be duly executed and delivered to Hydro such further instruments and other documents and do and cause to be done such further acts as may be necessary or desirable in the opinion of Hydro, acting reasonably, to carry out more effectively the provisions and purposes of the Loan Documents.

10.2 ~~10.2~~Negative Covenants.

So long as any amount owing under the Loan Documents remains unpaid or Hydro has any Credit Facility Commitment under this Agreement and unless Hydro, as the case may be, shall otherwise consent, TPC agrees not to:

(1) **Business Activity.** Engage in any business activity except the Business.

(2) **Liens**. Create, incur, assume or suffer to exist, any Lien on TPC's Property, including the Collateral and the Capital Stock of TPC other than Permitted Liens.

(3) **Disposal of Property.** Dispose of any of the Collateral without the prior written consent of Hydro.

(4) **Debt**. Allow, except with the prior consent of Hydro, any Debt to be created, incurred, assumed or suffered to exist, directly or contingently or otherwise, other than:

(a) Debt to Hydro;

(b) unsecured current liabilities incurred and payable in the ordinary course of the Business and not represented by any note, bond or debenture; or

(c) Purchase Money Debt, provided that the payments under such Purchase Money Debt do not exceed, in any one year period, $15,000.

(5) **Mergers**. Reorganize, amalgamate, merge, consolidate or otherwise enter into any form of business combination with any other Person.

(6) **Guarantees and Indemnities**. Guarantee or indemnify or give financial assistance in respect of any contingent liability in respect of any Debt or any other obligations or liabilities of any other Person at any time other than TPC's guarantee of the Debt owed by NCN to Hydro under the NCN Financing Agreement.

(7) ~~(7)~~ **Dividends.**

(a) Declare or pay any dividends or other distributions after Hydro has provided notice to TPC that an Event of Default has occurred; or

(b) Declare or pay any dividends or other distributions, in any other circumstances if, after declaring or paying such Dividends or other distributions, TPC would not be able to meet its Obligations under the Loan Documents.

(8) **Financial Year and Auditors**. Change its Financial Year end or its Auditors

(9) **Change in Constating Documents or Capital Stock.**

(a) Make any change in the constating documents or by-laws of TPC as delivered to Hydro which would:

(i) amend the authorized shares or other equity securities of TPC;

(ii) otherwise be detrimental to the rights or interests of Hydro under any of the Loan Documents.

(b) Issue any Capital Stock in TPC that would cause an Event of Default to occur or that would cause a Change of Control of TPC.

(10) **Material Agreements**. Amend, supplement, terminate or waive, or enter into any forbearance from exercising any rights with respect to, any of the terms of any Material Agreement in a manner which would cause a Material Adverse Business Effect or an Event of Default hereunder.

(11) **Limited Partnership Payments.** Make any payment to the Limited Partnership unless at least thirty (30) calendar days prior to the proposed date TPC intends to make the payment to the Limited Partnership it delivers to Hydro a statutory declaration signed by a duly authorized officer of TPC (each such statutory declaration a "**Limited Partnership Payment Certification**") which shall certify as to the source of the money to be used to make the proposed payment to the Limited Partnership and shall disclose all material information relating to the money to be used in respect of the proposed payment and shall attach notarized copies of all material documents. Hydro shall have the right to request from TPC, within five (5) calendar days of receipt of the Limited Partnership Payment Certification such additional information and notarized copies of documents relating to the monies to be used in respect of the proposed payment as it may require, acting reasonably, and to receive such written consents and waivers from TPC to obtain additional information and documents from any other Person relating to the monies to be used in respect of the proposed payment as Hydro may request, acting reasonably. Hydro shall be required to confirm in writing within twenty (20) calendar days of receipt of the Limited Partnership Payment Certification whether or not it will accept the Limited Partnership Payment

Certification, unless the time period is extended by Hydro, acting reasonably, due to Hydro awaiting receipt of the additional information and documents as it may have requested in connection to the Limited Partnership Payment Certification.

If Hydro accepts the Limited Partnership Payment Certification, TPC shall be permitted to make the proposed payment to the Limited Partnership on the condition it provides to Hydro (with concurrent notice to Hydro of the payment that is made to the Limited Partnership and for greater certainty the payment will under this Agreement be Approved Funds and will form part of TPC's Invested Cash), a statutory declaration signed by a duly authorized officer of TPC certifying there has been no material change to any of the information or documents provided by TPC in the Limited Partnership Payment Certification or obtained by Hydro concerning the monies being paid to the Limited Partnership, including the source of the monies. TPC shall not make the payment without providing the said statutory declaration. Hydro shall be required to accept the Limited Partnership Payment Certification, if Hydro determines, acting reasonably, that the monies being used for the payment fall within the definition of TPC's Own Funds or based on Hydro's analysis of the information disclosed and documents provided or otherwise obtained by Hydro. If based on Hydro's analysis, acting reasonably, Hydro determines that the said monies fall within the definition of TPC's Third Party Funds, then Hydro is entitled, acting reasonably, to reject or accept the Limited Partnership Payment Certification. In making that determination, Hydro will consider the source of the monies, the terms of any financing, any repayment requirements associated with the monies that have been provided, whether or not any Person has recourse against TPC's Units in the event of default in respect of any financing associated with obtaining the monies and, if so, the likelihood of that right being exercised. If Hydro rejects the Limited Partnership Payment Certification, TPC shall not be entitled to proceed with the proposed payment. If Hydro accepts the Limited Partnership's Payment

Certification, the payment can be made and the funds will be Approved Funds and once the payment is made, it shall form part of TPC's Invested Cash.

(12) **Change of Control.** There shall be no Change of Control.

(13) **Change of Registered Owner.** Change the registered owner of the Capital Stock of TPC to any person other than the Chief or a Councillor of NCN, as bare trustee for NCN, or change the form of bare trustee declaration prior to obtaining the written consent of Hydro to the change.

10.3 Cross-Default.

Any Event of Default (as defined in the NCN Financing Agreement) by TPC or by NCN shall be deemed to be an Event of Default hereunder.

ARTICLE XI
SECURITY

11.1 Security.

TPC shall execute and deliver the Security Documents to which it is a party, with each of the said Security Documents to be in form and substance satisfactory to Hydro, acting reasonably, as and when required hereunder or under the Loan Documents as continuing collateral security in the Collateral for the due, prompt and complete payment, performance and satisfaction by TPC of all of its indebtedness, liabilities and obligations of every nature whatsoever (whether present or future, direct or indirect, absolute or contingent, matured or unmatured, at any time due or accruing due, wheresoever and howsoever incurred, including any ultimate unpaid balance thereof, in any currency, and whether incurred prior to, at the time of or subsequent to the execution of this Agreement) to Hydro, in connection with this Agreement and the other Loan Documents (collectively, the "**Obligations**").

11.2 Security Documents Prevalence.

Notwithstanding anything to the contrary herein, this Agreement shall be interpreted in all respects having regard for the fact that, and the Security Documents shall provide that, (a) Hydro has a first charge security interest on TPC's Units and the Distributions on TPC's Units and any interest related to TPC's Units and the said Distributions; and (b) Hydro's sole recourse for payment of the Obligations shall be to the Collateral in accordance with the provisions of this Agreement, and for greater certainty, it shall have no right to sue TPC or NCN on any personal covenant to pay all or any of the Obligations. Without limiting the generality of the foregoing, it is agreed, and the Security Documents shall provide that if TPC is in default of the repayment provisions specified in Section 2.5, Hydro's sole recourse for the payment of the Total Outstandings under (and all other amounts owing to Hydro for costs, interest or otherwise in connection with) the Equity Credit Facility on the Maturity Date shall be to TPC's Loan Units and the Distributions thereon~~, and that if TPC is in default of repayment provisions specified in Section 3.5(3), Hydro's sole recourse for payment of the Total Outstandings under (and all other amounts owing to Hydro for costs, interests or otherwise in connection with) the Cash Call Credit Facility on the Maturity Date which are attributable to Cash Call Credit Advances made in respect of TPC's Loan Units shall be to TPC's Loan Units and the Distributions thereon~~.

11.3 ~~11.2~~Registrations.

~~(1)~~ Hydro, in its sole discretion, may register, file or record the Liens constituted by the Security Documents in all jurisdictions where such registration, filing, or recording is necessary or of advantage to the creation, perfection, preservation or protection of such Liens.

11.4 Renewals Registrations, Filings, Recordings.

~~(2)~~ Hydro may renew such registrations, filings and recordings from time to time as and when required or of advantage, in the sole discretion of Hydro, to keep them in full force and effect. TPC acknowledges that the forms of the Security Documents have been prepared based upon the Laws of the jurisdictions indicated therein as being applicable thereto in effect at the date hereof and that such Laws may change. TPC agrees that, following prior notice to and consultation with TPC, upon direction from Hydro, shall have the right to require that the forms of the Security Documents be amended, restated or supplemented, to reflect any changes in such Laws, whether arising as a result of statutory amendments, court decisions or other similar changes, in order to confer upon Hydro the Liens in the Collateral intended to be created by the Security Documents, in the sole discretion of Hydro. For greater certainty, nothing in this Agreement can be used by Hydro or TPC to expand or reduce or otherwise change the scope of the Property comprising the Collateral as defined herein or to confer upon Hydro a right to sue TPC or NCN on a personal covenant to pay all or any of the Obligations, or to require any guarantees, indemnities or covenants from NCN or any other Person in respect of the Obligations or otherwise.

ARTICLE XII
EVENTS OF DEFAULT

12.1 Events of Default.

If any of the following events, conditions or circumstances (each an "**Event of Default**") shall occur and be continuing:

(a) TPC shall fail to pay any portion of the principal or interest or any costs or other amounts due hereunder or under any of the other Loan Documents on the date when due hereunder, and such amount remains unpaid for a period of six (6)

Business Days after Hydro notifies TPC that the amount is overdue, provided however, that this provision shall be read in conjunction with Section 12.2 and with the provisions in this Agreement and the other Loan Documents which provide that, for so long as no Event of Default has occurred that remains outstanding and uncured, all such payments to Hydro are to be made solely through the irrevocable assignment and direction to Hydro of the Distributions on TPC's Units (or portion thereof, as applicable hereunder) prior to the Maturity Date (and, in certain circumstances hereunder, after the Maturity Date), and from no other source, such that for so long as the Distributions are so assigned and directed and are paid over to Hydro as and when declared by the General Partner of the Limited Partnership pursuant to the irrevocable assignment and direction in favour of Hydro, TPC shall be deemed to be in compliance with its covenants to pay for all purposes hereunder and under the other Loan Documents. The parties hereto acknowledge that neither TPC nor NCN control the timing or amount of such Distributions, and as such, there may be periods of time during which there are no or few Distributions to be paid over to Hydro in accordance with the irrevocable assignment and direction to Hydro, and this shall not be construed to be an Event of Default hereunder;

(b) any representation or warranty or certification made or deemed to be made by TPC pursuant to or in connection with any of the Loan Documents delivered to Hydro shall prove to have been incorrect in any material respect when made or deemed to have been made;

(c) TPC shall fail to perform or observe any other term, covenant or agreement contained in any of the Loan Documents on its part to be performed or observed and such failure shall remain unremedied for fifteen (15) Business Days (the "**Cure Period**") after written notice thereof shall have been given to TPC by Hydro; provided that the length of the Cure Period shall be extended by Hydro in its unfettered discretion where TPC demonstrates to Hydro that the breach is not capable of being cured within fifteen (15) Business Days but provides Hydro, within ten (10) Business Days, with a plan for curing the breach within sixty (60) calendar days and in good faith implements such plan;

(d) any of the Loan Documents, at any time, is not or ceases to be valid or enforceable in whole or in part, or if any Lien intended to be created by any of the Security Documents is not or ceases to be a valid and perfected Lien having the ranking or priority contemplated thereby, or if the validity or enforceability of any of the Loan Documents or the validity or perfection of any such Lien shall be contested by any party thereto or any other Person (unless such contestation by such party or other Person is being opposed diligently, in good faith and by proper legal proceedings by Hydro with the assistance of TPC and Hydro covenants to oppose such contestation in good faith where there is a reasonable prospect of success), or if any Person (other than Hydro or the Limited Partnership) obtains any interest in the Collateral or any part thereof (except Permitted Liens); provided however, that this provision shall only be invoked where Hydro, acting reasonably, has determined that its inability to enforce the said Lien with its intended ranking or priority cannot be cured by Hydro within a reasonable period of time or without Hydro being adversely affected notwithstanding that TPC has provided a written undertaking to assist Hydro in the manner set out therein to cure the inability of Hydro to enforce the said Lien with its intended ranking or priority;.

(e) with respect to Debt of TPC under any one or more agreements other than the Debt under the Loan Documents,

(i) TPC shall fail to pay any principal, interest or other amount pursuant to the agreements governing such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) when such amount becomes due and payable (whether by scheduled maturity, required repayment, acceleration, demand or otherwise) and such failure shall continue after any applicable grace period specified in such agreement or agreements; or

(ii) any other event, condition or circumstance shall occur and shall continue after any applicable grace period specified in such agreement or agreements, if the effect of such event, condition or circumstance is to accelerate the maturity of such other Debt in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency); or

(iii) other Debt of TPC in an aggregate amount in excess of $75,000 (or the equivalent amount in another currency) shall be declared to be due and payable prior to the stated maturity thereof under any such agreement or agreements;

(f) the occurrence of any default, or any event or condition which, with the giving of notice or passage of time, or both, would constitute a default by TPC under any Material Agreement, and such default shall continue unremedied after any applicable grace period specified in such Material Agreement;

(g) TPC shall:

(i) become insolvent;

(ii) admit in writing its inability to pay its debts generally or shall make a general assignment for the benefit of creditors;

(iii) file a notice of intention to file a proposal under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors;

(iv) institute or have instituted against it any proceeding seeking (x) to adjudicate it a bankrupt or insolvent, (y) any liquidation, winding-up, reorganization, arrangement, adjustment, protection, relief or composition of it or its debts under any Law relating to bankruptcy, insolvency or reorganization or relief of debtors, or (z) the entry of an order for relief or the appointment of a Receiver, interim Receiver, Receiver and manager, assignee, liquidator, sequestrator, trustee or other similar official for it or for any substantial part of its Property, and in the case of any such proceeding instituted against it (but not instituted by it), it shall not be dismissed or stayed within forty-five (45) days of its commencement or issuance or any of the actions sought in such proceeding (including the entry of an order for relief against it or the appointment of a Receiver, trustee, custodian or other similar official for it or for any substantial part of its Property) shall occur; or

(v) take any corporate action to authorize any of the foregoing actions;

(h) a Notice is sent to or received by TPC from any creditor with respect to the intention of such creditor to enforce a Lien on:

(i) any of the Collateral; or

(ii) any Property of TPC (other than the Collateral) unless such notice is being contested in good faith by appropriate legal proceedings and such notice has not resulted in, or does not involve, any danger of the sale, forfeiture or loss of any of the Collateral;

(i) any one or more judgments or orders in excess of $75,000 (or the equivalent in another currency) in the aggregate, or any one or more orders, directives, letters of credit or other communications from any Governmental Entity which may be reasonably likely to require TPC to expend an amount in excess of $75,000 (or the equivalent amount in another currency) in the aggregate shall be rendered against TPC, and either:

   (i) enforcement proceedings shall have been commenced by any creditor upon any such judgment(s) or order(s); or

   (ii) there shall be any period of ten (10) consecutive Business Days during which a stay of enforcement of any such judgment or order, directive, letter or other communication by reason of a pending appeal or otherwise, shall not be in effect;

(j) the audited financial statements of TPC in respect of any Financial Year are qualified in any material adverse respect by the Auditors;

(k) the occurrence of a Change of Control;

(l) the loss, suspension or failure to renew any licence or permit held by TPC or any agreement to which TPC is a party the effect of which would prohibit or otherwise restrict TPC from conducting all or a material part of the Business;

(m) TPC is enjoined or restrained in any material way by an order of any Governmental Entity, arbitrator or board in Canada or elsewhere from conducting all or a material part of the Business;

(n) the occurrence of a Material Adverse Business Effect;

(o) the occurrence of an Event of Default committed by TPC or NCN (as such term is defined in the NCN Financing Agreement); or

(p) the occurrence of any event, condition or circumstance which, with the giving of notice or passage of time, or both, would constitute an Event of Default after the expiration of, in the case of a Loan Document, the applicable Cure Period or in the case of any other agreement, the applicable cure period (if any) thereunder;

then, and in any such event, Hydro shall be entitled by written notice to TPC to: (i) terminate the obligation of Hydro to make further Advances under the Equity Credit ~~Facilities~~Facility; and/or (ii) demand repayment of all indebtedness of TPC to Hydro under the Equity Credit ~~Facilities~~Facility, whereupon the principal amount of all outstanding Advances and other amounts payable thereunder shall become forthwith due and payable, without presentment, demand, protest or further notice of any kind, all of which are hereby expressly waived by TPC (except such notices as may be required under applicable Laws). Provided, however, that Hydro shall only have recourse to the Collateral for the repayment of the Obligations, and further provided, however, that upon any Event of Default specified in Section 12.1(g), the obligation of Hydro to make Advances hereunder shall automatically terminate.

12.2 ~~12.2~~Expenses of Hydro.

Upon the occurrence of any Event of Default which has not been waived and is continuing, Hydro may take any action Hydro considers advisable, acting reasonably, to remedy the effect of such Event of Default. All reasonable expenses, costs and charges incurred by or on behalf of Hydro in connection with: (i) any remedial action taken pursuant to this Section; or (ii) the realization of the Collateral, including all reasonable fees, court costs, Receiver's or agent's remuneration and other expenses of taking possession of, repairing, protecting, insuring, preparing for disposition, realizing, collecting, selling, transferring, delivering or obtaining payment of the Collateral, in all cases shall be added to and form a part of the Obligations, but subject always to the provision that Hydro's sole recourse for payment of the Obligations shall be to the Collateral, as set out herein. For greater certainty, for so long as there is no Event of Default hereunder, Section 5.14 of the PDA shall govern the payment of Hydro's costs and expenses properly recoverable hereunder.

12.3 Remedies Cumulative.

The remedies provided for in this Agreement and each of the Loan Documents are cumulative and do not exclude any other right or remedy provided by Law (except that there shall be no right of Hydro to sue TPC or NCN on any personal covenant to pay, it being acknowledged that Hydro's sole recourse is to the Collateral).

12.4 ~~12.4~~Allocations.

For greater certainty, the parties agree that any expenses or costs that are, by the terms of this Agreement, reimbursable to Hydro shall be allocated ~~as follows: if the expense or cost is incurred by Hydro prior to or on the Adjustment Date or is incurred by Hydro after the Adjustment Date but in respect of a matter arising in connection with the Equity Credit Facility, it shall be allocated to the Equity Credit Facility. If the expense or cost is incurred by Hydro after the Adjustment Date (except where it is incurred in respect of a matter arising in connection with the Equity Credit Facility), it shall be allocated to the Cash Call~~ to the Equity Credit Facility.

ARTICLE XIII
PAYMENTS, COMPUTATIONS AND INDEMNITIES

13.1 Timing of TPC Payments~~under this Agreement~~.

~~(1)~~ Unless otherwise expressly provided in this Agreement or agreed to by Hydro, TPC shall make any payment required to be made by it to Hydro by depositing the amount of such payment in Hydro's Account not later than 11:00 a.m. (Winnipeg time) on the date such payment is due.

13.2 Timing of Hydro Payments.

~~(2)~~ Unless otherwise expressly provided in this Agreement and subject to the provision by Hydro of the requisite notice to TPC and the General Partner as set out in Section 4.2(1), Hydro shall make any Advance or other payment to TPC hereunder by crediting or causing the crediting of the Limited Partnership Account for TPC with the amount of such Advance on the date such Advance is to be made.

~~13.2~~ 13.3 Payments on Non-Business Days.

Whenever any payment hereunder shall be stated to be due on a day other than a Business Day, such payment shall be made on the next succeeding Business Day, and such extension of time shall in such case be included in the computation of interest or fees, as the case may be.

~~13.3~~ 13.4 Overdue Amounts.

All amounts owed by TPC which are not paid when due (whether at stated maturity, on demand, by acceleration or otherwise) shall bear interest (both before and after judgment), from the date on which such amount is due until such amount is paid in full, payable on demand, at a rate per annum equal at all times to the rate in effect on the date the said amounts are due and unpaid.

~~13.4~~ 13.5 Application of Payments, Repayments and Prepayments.

All amounts received by Hydro from or on behalf of TPC, including from realization by Hydro on the Collateral of the Security, and not previously applied pursuant to this Agreement shall be applied:

(a) first, in reduction of TPC's obligation to pay any costs and expenses, which are due and owing to Hydro and reimbursable or indemnity amounts or Losses which have been determined by a court of competent jurisdiction or by arbitration to be due and owing to Hydro;

(b) second, in reduction of TPC's obligation to pay any unpaid interest accrued on the principal amount of Advances;

(c) third, in reduction of TPC's obligation to pay any amounts due and owing on account the principal amount of all Advances; and

(d) fourth, to be held in escrow by Hydro in an interest-bearing account on account, and up to the amount, of any written claim by Hydro then issued and outstanding seeking reimbursement or indemnity hereunder for Losses, pending determination by a court of competent jurisdiction or by arbitration as to the amount (if any) which is due and owing to Hydro hereunder (in which event, such funds and any interest earned thereon shall be dealt with in accordance with the order of the court of competent jurisdiction or arbitrator, as the case may be); and

(e) fifth, to TPC or such other Persons as may lawfully be entitled to the remainder or as any court of competent jurisdiction may otherwise direct.

~~13.5~~ 13.6 Computations of Interest and Fees.

~~(1)~~ All computations of interest shall be made by Hydro, taking into account the actual number of days occurring in the period for which such interest is payable pursuant to Sections 4.4(a)(i) and on the basis of a year of 365 days, except for interest payable under Sections 4.4(a)(ii)~~,~~ and 4.4(a)(iii),~~ 4.4(b) and 4.5,~~ in respect of which the computation of interest shall be made based on a semi-annual interest computation and not by the number of days in the six (6) month period.

~~(2)~~ Notwithstanding any provision to the contrary contained in this Agreement, in no event shall the aggregate "interest" (as defined in Section 347 of the *Criminal Code* (Canada), as the same may be amended, replaced or re-enacted from time to time) payable under this Agreement exceed the maximum amount of interest on the "credit advanced" (as defined in that Section) under this Agreement lawfully permitted under that Section and, if any payment, collection or demand pursuant to this Agreement in respect of "interest" (as defined in that Section) is determined to be contrary to the provisions of that Section, such payment, collection or demand shall be refunded to TPC. For purposes of this Agreement, the effective annual rate of interest shall be determined in accordance with generally accepted actuarial practices and principles over the term that the ~~relevant~~Equity Credit ~~Facilities are~~Facility is outstanding on the basis of annual compounding of the lawfully permitted rate of interest and, in the event of any dispute, a certificate of a Fellow of the Canadian Institute of Actuaries appointed by Hydro will be conclusive for the purposes of such determination.

~~(3)~~ Each determination by Hydro of any amount payable hereunder by TPC shall be prima facie evidence of the amount payable for all purposes absent error.

~~13.6~~ 13.7 Indemnity for Change in Circumstances.

~~(1)~~ If with respect to Hydro:

~~(a)~~ (a) any change in Law, or any change in the interpretation or application by any Governmental Entity of any Law occurring or becoming effective after the date hereof; or

~~(b)~~ (b) any compliance by Hydro with any direction or requirement having the force of Law of any Governmental Entity made or becoming effective after the date hereof, in either case shall have the effect of causing Loss to Hydro by:

(i) increasing the actual cost to Hydro of performing its obligations under this Agreement or in respect of any Advance; or

(ii) reducing any amount otherwise properly payable to Hydro under this Agreement or in respect of any Advance by any amount that Hydro deems material acting reasonably (other than pursuant to Section ~~13.5(2)~~13.6);

then Hydro may give notice to TPC specifying the nature of the event giving rise to such Loss and TPC shall, within twenty (20) Business Days of demand, pay such amounts as Hydro may specify is necessary to compensate Hydro for such Loss. A certificate as to the amount of any such Loss, submitted in good faith by Hydro to TPC shall be prima facie evidence of the amount of such Loss for all purposes, absent error.

13.8 Taxes on TPC Payments.

~~(2)~~ Except as required by applicable Law, TPC shall make all payments under this Agreement to Hydro without deducting or withholding of any Taxes. To the extent that deduction or withholding of Taxes is required by applicable Law, TPC will:

~~(a)~~ (a) promptly notify Hydro of such requirement;

~~(b)~~ (b) pay to the appropriate authority the full amount required to be so withheld or deducted before penalties attach thereto or interest accrues thereon;

~~(c)~~ (c) promptly forward to Hydro an official receipt or other documentation reasonably satisfactory to Hydro evidencing such payment to such authority; and

~~(d)~~ (d) pay to Hydro an additional amount so that Hydro receives the full amount it would have received had no such deduction or withholding been required.

If any Taxes are directly asserted against Hydro with respect to any payment under this Agreement, Hydro may pay such Taxes and TPC shall promptly pay such additional amount (including any penalties, interest and expenses) necessary so that the net amount received by Hydro after the payment of such Taxes, including any Taxes on such additional amounts, shall equal the amount Hydro would have received had Hydro not paid such Taxes.

TPC will indemnify Hydro for all incremental Taxes, interest or penalties that Hydro must pay if TPC fails to deduct or withhold any Taxes when due or to send Hydro the required receipts or other documentation.

Hydro acknowledges that in respect of this Section 13.6(2), Taxes shall not include any income taxes that may be payable by Hydro. Hydro shall remain solely obligated to pay and shall save TPC and NCN harmless from any income taxes that may be asserted against Hydro or payable by Hydro, including with respect to any payments or amounts received or made under this Agreement.

~~13.7~~ 13.9 Indemnity.

~~(1)~~ TPC hereby agrees to indemnify, exonerate and hold Hydro and its officers, directors, employees, agents and other representatives (in this Section 13.7(1), the "**Indemnified Parties**") free and harmless from and against any and all Claims, demands, actions, causes of action, suits, losses, costs (including all documentary, recording, filing, mortgage duties), charges, liabilities and damages, and expenses in connection therewith (irrespective of whether such Indemnified

Party is a party to the action for which such indemnification hereunder is sought), and including reasonable legal fees and disbursements (collectively, in this Section 13.7(1), the "**Indemnified Liabilities**") paid, incurred or suffered by, or asserted against, the Indemnified Parties or any of them or, with respect to, or as a direct or indirect result of: (i) any transaction financed or to be financed in whole or in part, directly or indirectly, with the proceeds of any Advances obtained hereunder; or (ii) the execution, delivery, performance or enforcement of this Agreement or any of the Loan Documents, except for such Indemnified Liabilities that a court of competent jurisdiction determines or rules to be on account of the relevant gross negligence or willful misconduct of the Indemnified Party or any Person for whom such Indemnified Party is responsible at law (in which event, such Party shall indemnify TPC, and its officers and directors, for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct).

~~(2) All obligations provided for in this Section 13.7 shall not be reduced or impaired by any investigation made by or on behalf of Hydro.~~

13.10 TPC Obligations.

~~(3)~~ All obligations provided for in this Section 13.7 shall not be reduced or impaired by any investigation made by or on behalf of Hydro. If, for any reason, the obligations of TPC pursuant to this Section 13.7 shall be unenforceable, TPC agrees to make the maximum contribution to the payment and satisfaction of each obligation that is permissible under Law, except to the extent that a court of competent jurisdiction determines such obligations arose on account of the gross negligence or willful misconduct of Hydro or any Person for whom Hydro is responsible at law (in which event such Party shall indemnify TPC, and its officers and directors for all Indemnified Liabilities paid, incurred or suffered by or asserted against any of them arising out of such gross negligence or willful misconduct).

~~13.8~~ 13.11 Contribution.

If any provision in any of the Loan Documents providing for indemnification by TPC (the "**Indemnitor**") in favour of Hydro or any of the Indemnified Parties (as defined in Section 13.7) (the "**Indemnitee**") is found by reason of the occurrence of an event, other than the gross negligence or wilful misconduct of the Indemnitee, to be unenforceable by a court of competent jurisdiction in a final judgment that has become non-appealable, then the Indemnitor shall contribute to the amount paid or payable by the Indemnitee which is subject to the indemnification provision in such proportion as is appropriate to reflect not only the relative benefits received by the Indemnitor on the one hand and the Indemnitee on the other hand but also the relative fault of the Indemnitor and the Indemnitee but only to the extent that such contribution is consistent with the terms of the final judgment. The rights of contribution herein provided shall be in addition to and not in derogation of any other right to contribution which the Indemnitee may have under this Agreement or applicable Laws.

~~13.9~~ 13.12 Market Make-whole Payment

In the event of a voluntary payment of principal by TPC to Hydro ~~hereunder~~ prior to the date on which such payment is due and payable (other than any payment of interest or costs whatsoever or any payment out of Distributions, including payments of principal pursuant to any of Sections 2.6(2), 2.6~~(5), 2.6(6), 3.6~~(2) ~~and 3.6(3)~~ from Distributions on TPC's Units ~~from time to time~~), the principal amount of the repayment shall be ~~adjusted by the amount determined in the following manner:~~ an amount calculated by Hydro on the Business Day preceding the date of repayment equal to the applicable Canada Yield Price on the Business Day preceding the date of the payment less the principal amount of the Equity Credit Advances that are being repaid. For greater certainty, if the amount so determined is a positive number it shall increase the principal amount to be repaid by that amount, and if it is a negative number it shall reduce the principal amount to be repaid by that amount.

~~(a) Equity Credit Advances. An amount calculated by Hydro on the Business Day preceding the date of repayment equal to the applicable Canada Yield Price on the Business Day preceding the date of the payment less the principal amount of the Equity Credit Advances that are being repaid. For greater certainty, if the amount so determined is a positive number it shall increase the principal amount to be repaid by that amount, and if it is a negative number it shall reduce the principal amount to be repaid by that amount.~~

~~(b) Cash Call Credit Advances. An amount calculated by Hydro on the Business Day preceding the date of repayment equal to the applicable Canada Yield Price on the Business Day preceding the date of the payment less the principal amount of the Cash Call Credit Advances that are being repaid. For greater certainty, if the amount so determined is a positive number it shall increase the principal amount to be repaid by that amount, and if it is a negative number it shall reduce the principal amount to be repaid by that amount.~~

~~13.10~~ 13.13 Confirmation of Limited Recourse.

For greater certainty, Hydro acknowledges that nothing in this Article XIII shall in any way detract from the limited recourse nature of Hydro's security and remedies hereunder, as set out in Section 11.1 ~~hereof.~~of this Agreement.

ARTICLE XIV
DISPUTE RESOLUTION

14.1 Dispute Resolution.

Each of the parties to ~~the~~this Agreement agrees that any disputes or claims arising out of this Agreement shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the PDA and it shall not bring any action in respect of any matter arising hereunder, other than pursuant to Article XXI of the PDA, against any other party.

ARTICLE XV
GENERAL PROVISIONS

15.1 Notices.

~~(1)~~ All notices provided for in this Agreement or in the other Loan Documents shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name in Schedule F hereto or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made during normal business hours of the recipient; otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

~~(2)~~ Each Borrowing Notice and Repayment Notice shall be irrevocable and binding on TPC.

15.2 ~~15.2~~ Time of the Essence.

Time shall be of the essence of this Agreement.

15.3 Third Party Beneficiaries.

Each party hereto intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any Person, other than the parties hereto and the Persons contemplated in Section 13.7 or Section 15.7, and no Person, other than the parties hereto and the Persons contemplated in Section 13.7 or Section 15.7, shall be entitled to rely on the provisions hereof in any action, suit, proceeding, hearing or other forum. For greater certainty, nothing in this Section 15.3 is intended to prevent or restrict the Taskinigaph Trust from receiving Dividends declared by the Board of Directors of TPC pursuant to the NCN Deed of Assignment subject always to TPC's compliance with the covenants, representations and warranties of this Agreement.

15.4 ~~15.4~~ Enurement.

~~This~~his Agreement shall enure to the benefit of and be binding upon the ~~parties hereto~~Parties . This Agreement shall be binding upon any assigns and enure to the benefit of any permitted assigns.

15.5 ~~15.5~~ Counterparts.

~~This~~ Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which, taken together, shall constitute one and the same instrument.

15.6 Knowledge.

Where any representation or warranty contained in this Agreement or any other Loan Documents is expressly qualified by reference to the "best of the knowledge" of TPC, or where any other reference is made herein or in any Loan Document to "the knowledge" of TPC, it shall be deemed to refer to the best of the knowledge of the members of the Board of Directors of TPC.

15.7 ~~15.7~~Assignment.

Neither this Agreement nor the rights and obligations ~~hereunder~~ under this Agreement shall be assignable or transferable by TPC or Hydro, except that Hydro may assign this Agreement to any Affiliate, on the condition that notwithstanding the assignment, Hydro will remain jointly and severally liable with the said Affiliate, for compliance with the covenants of Hydro under this Agreement.

15.8 ~~15.8~~Non-Merger.

Except as otherwise expressly provided in this Agreement, the covenants, representations and warranties of the ~~parties contained~~ Parties in this Agreement and ~~any of~~ the ~~other~~ Loan Documents shall not merge on and shall survive the Initial Closing, the Final Closing and the Final Investment Closing and the making of any Advance, and notwithstanding such Initial Closing and Final Closing and the Final Investment or Advance, or any investigation made by or on behalf of any party, shall continue in full force and effect. Neither the Initial Closing, the Final Closing or the Final Investment Closing nor the making of any Advance shall prejudice any right of one party against any other party in respect of anything done or omitted hereunder or under any of the other Loan Documents or in respect of any right to damages or other remedies.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, on the date first above written.

TASKINIGAHP POWER CORPORATION

Per:

Name: ~~Jerry Primrose~~
Title: President

Per:

Name: ~~William Elvis Thomas~~
Title: Vice- President

Per:

Name: Shirley L. Linklater
Title: Secretary-Treasurer

THE MANITOBA HYDRO-ELECTRIC BOARD

Per:

Name: ~~Robert B. Brennan~~
Title: President and Chief Executive Officer

Per:

Name: ~~Robert D. Brennan~~
Title: Assistant Corporate Secretary

SCHEDULE A

REPAYMENT NOTICE

TO: THE MANITOBA HYDRO-ELECTRIC BOARD (“Hydro”)

FROM: TASKINIGAHP POWER CORPORATION (“TPC”)

This Repayment Notice is delivered to you pursuant to Section 4.6 of the financing agreement (the “TPC Financing Agreement”) dated ●, ~~2006~~2015 between TPC, as borrower, and Hydro, as lender. All capitalized terms used in this Repayment Notice and defined in the TPC Financing Agreement shall have the meanings defined in the TPC Financing Agreement.

1. TPC hereby gives notice of repayment as follows:

   (a) Date of repayment:

   (b) Type of Advance:

   (c) Amount of principal being repaid:

TASKINIGAHP POWER CORPORATION

Per:
Name:
Title:

Per:
Name:
Title:

SCHEDULE B

~~BORROWING NOTICE~~

~~To: THE MANITOBA HYDRO-ELECTRIC BOARD ("Hydro")~~

~~From: TASKINIGAHP POWER CORPORATION ("TPC")~~

~~This Borrowing Notice is delivered to you pursuant to Section 4.2(1) of the financing agreement (the "TPC Financing Agreement") dated ●, 2006 between TPC, as borrower, and Hydro, as lender. All capitalized terms used in this Borrowing Notice and defined in the TPC Financing Agreement shall have the meanings defined in the TPC Financing Agreement.~~

~~1. TPC hereby requests an Advance as follows:~~

~~(a) Date of Advance:~~

~~(b) Amount of Advance:~~

~~(c) Type of Advance:~~

~~(d) Payment Instructions:~~

~~2. TPC hereby certifies that :~~

~~(a) All of the representations and warranties of TPC contained in Section 9.1 of the TPC Financing Agreement are true and correct in all material respects on and as of the date hereof as though made on and as of the date hereof (other than those representations and warranties in Section 9.1 which are specifically limited to a particular date) and except as disclosed in writing to, and accepted in writing by Hydro.~~

~~(b) All of the covenants of TPC contained in Article X of the TPC Financing Agreement together with all of the conditions precedent to an Advance in Article VII of the TPC Financing Agreement (to the extent they are within TPC's control) have been complied with or met in all materials respects, except as disclosed in writing to, and accepted in writing by Hydro.~~

~~(c) No Event of Default has occurred and is continuing on the date hereof nor will any Event of Default occur as a result of the aforementioned Advance, except as disclosed in writing to, and accepted in writing by Hydro.~~

~~DATED:~~ ~~TASKINIGAHP POWER CORPORATION~~

~~Per:~~
~~Name:~~
~~Title:~~

~~Per:~~
~~Name:~~
~~Title:~~

[intentionally blank]

SCHEDULE C

ISSUED AND OUTSTANDING CAPITAL STOCK AND DEBT

To be provided on ~~Initial Closing~~Final Investment Date

SCHEDULE D

MATERIAL AGREEMENTS

~~To be provided~~Provided on Initial Closing

SCHEDULE E

LIABILITIES

~~To be provided~~Provided on Initial Closing

SCHEDULE F

ADDRESS FOR NOTICE

Taskinigahp Power Corporation
Attention: President
General Delivery
Nelson House, MB R0B 1A0
Fax: (204) 484-2392

Manitoba Hydro
Attention: General Counsel
~~3rd Floor – 820 Taylor~~360 Portage Avenue
Winnipeg, ~~MBR~~MB R3C ~~2P4~~0G8
Fax: (204) ~~474~~360-4947

SCHEDULE G

LIST OF SECURITY DOCUMENTS

1. TPC Security Agreement
2. Pledge of TPC’s Units
3. Limited Power of Attorney granted by TPC respecting TPC’s Units

SCHEDULE H

AUTHORIZATIONS – HYDRO

1. Order in Council as required pursuant to the provisions of the Hydro Act.
2. Such Additional Borrowing Authorizations required from time to time.

Document comparison by Workshare Compare on May-12-15 12:54:02 PM

Input:	
Document 1 ID	PowerDocs://TDSLAW/445350/24
Description	TDSLAW-#445350-v24-TPC_Financing_Agreement
Document 2 ID	file://C:/Users/nicolel/AppData/Roaming/OpenText/DM/Temp/TDSLAW-#1788643-v30-2014_Restated_TPC_Financing_Agreement_.docx
Description	TDSLAW-#1788643-v30-2014_Restated_TPC_Financing_Agreement_
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	453
Deletions	848
Moved from	15
Moved to	15
Style change	0
Format changed	0
Total changes	1331

SECOND AMENDED AND RESTATED LIMITED PARTNERSHIP AGREEMENT

between

5022649 MANITOBA LTD.,

- and -

TASKINIGAHP POWER CORPORATION,

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD.

DATED ~~June 28, 2006.~~as of March 31, 2015

TABLE OF CONTENTS

**SECOND AMENDED AND RESTATED
LIMITED PARTNERSHIP AGREEMENT**

This Agreement made ~~on~~as of the ~~28th~~31st day of ~~June~~March, ~~2006.~~2015.

BETWEEN:

5022649 MANITOBA LTD.,

(hereinafter called the "**General Partner**"),

OF THE FIRST PART,

- and -

TASKINIGAHP POWER CORPORATION,

(hereinafter called "**Taskinigahp Power Corporation**"),

OF THE SECOND PART

- and -

THE MANITOBA HYDRO-ELECTRIC BOARD,

(hereinafter called "**Hydro**"),

OF THE THIRD PART.

WHEREAS the **General Partner** was incorporated under the laws of the Province of Manitoba on November 30, 2004;

AND WHEREAS a partnership agreement (the "**Initial Agreement**") was entered into on the 9th day of December, 2004, between the **General Partner** and the **Initial Limited Partner**;

AND WHEREAS under the **Initial Agreement**, the **General Partner** and the **Initial Limited Partner** formed a partnership known as the Wuskwatim Power Limited Partnership (the "**Partnership**") which was registered in accordance with the laws of the Province of Manitoba as a limited partnership on the 9th day of December 2004;

AND WHEREAS the **Initial Agreement** was amended and restated pursuant to an agreement dated the 28th day of June, 2006 between the **General Partner**, **Taskinigahp Power Corporation** and **Hydro ("First Amended and Restated Agreement");**

NOW THEREFORE in consideration of the premises herein contained and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereto hereby agree as follows:

ARTICLE I

GENERAL INTERPRETATION

Definitions

1.01 For the purpose of this Agreement, the following terms shall be deemed to have the following meanings:

(a) "**Act**" means *The Partnership Act* (Manitoba);

(b) "**Affiliate**" has the meaning ascribed to affiliate or associate as those terms are defined in *The Securities Act* (Manitoba);

(c) "**Agreement**" means this Amended and Restated Limited Partnership Agreement and any amendments or modifications made thereto, including without limitation any schedules or appendices attached hereto;

(d) "**Allowable Operating Expenses**" means all expenses incurred directly or indirectly by the **General Partner** in managing the **Business** of the **Partnership**, including, without limiting the type of expenses, all administrative expenses, including the costs of holding meetings of the board of directors of the **General Partner** and preparing financial statements of the **General Partner** but, for greater certainty, shall not include any costs other than costs incurred in furtherance of the **Business** or which are properly allocated, in whole or in part, to the **Business**, and, without limiting the generality of the foregoing, shall not include any of the costs incurred by **Hydro** in building the project known as the Churchill River Diversion nor any of the costs incurred by **Hydro** and allocated to the operation of the project known as the Churchill River Diversion;

(e) "**Business**" shall have the meaning ascribed to it in section 2.05 hereof;

(f) "**Capital Contribution**" means, with respect to a **Partner**, the amount in cash or other property contributed to the **Partnership** by such **Partner**;

(g) "**Construction Agreement**" means the agreement to be entered into by the **Partnership** as owner and **Hydro** as project manager in substantially the same form as described in the **PDA**;

(h) "**Declaration**" means the declaration pursuant to the Act to be filed under *The Business Names Registration Act* of Manitoba;

(i) "**Debt Ratio**" ~~shall have the meaning ascribed thereto~~means for any particular day, the quotient of the Limited Partnership's Net Debt (as defined in the Project Financing Agreement~~;~~) on such day divided by the sum of: (i) the Limited Partnership's Net Debt on such day; and (ii) the Limited Partnership's Equity (as defined in the Project Financing Agreement) on such day, expressed as a percentage;

(j) "**Distributable Cash**" in respect of any distribution period, means **EBITDA** earned by the **Partnership** for such period, plus any additional cash on hand at the end of a distribution period and any additional amounts that the **General Partner** approves for distribution, less: (i) payments to satisfy debt service obligations (including principal, interest and deposits for debt retirement) incurred in such period under credit facilities of the **Partnership** (including under the **Project Financing Agreement**) or other agreements to which the **Partnership** is bound; (ii) payments to satisfy general and administrative expenses and other known expense obligations of the **Partnership**; and (iii) amounts retained in respect of the distribution period to cover (1) anticipated expenses, (2) reserves under section 6.06 of this **Agreement** and (3) the amount (if any) required to be held as equity in order to maintain the **Debt Ratio** in accordance with section 6.05;

(k) "**EBITDA**" for any period means earnings before interest, income taxes, depreciation and amortization, determined in accordance with **Generally Accepted Accounting Principles** ("earnings" for this purpose means the **Net Income** or **Net Loss**, as applicable, for that period);

(l) "**Final Closing Date**" has the meaning ascribed thereto in the **PDA**;

(m) "**Financial Statements**" shall mean the audited financial statements of the **Partnership** prepared in accordance with **Generally Accepted Accounting Principles**;

(n) "**Fiscal Year**" means the fiscal year of the **Partnership** as described in section 2.04;

(o) "**General Partner**" shall mean 5022649 Manitoba Ltd. or any other **Person** who may become the general partner of the **Partnership** in place of or substitution for 5022649 Manitoba Ltd. and is deemed to be the **General Partner** from time to time under the terms of this **Agreement**;

(p) "**Generally Accepted Accounting Principles**" means, at any time, accounting principles as recommended by the Canadian Institute of Chartered Accountants, or any successor **Person** at such time;

(q) "**Hydro**" means The Manitoba Hydro-Electric Board, a Crown corporation continued by The Manitoba Hydro Act, R.S.M. 1987, c.H190;

(r) "**Hydro Service Agreements**" means, collectively, the Management Agreement, the Project Financing Agreement, the Construction Agreement, the Power Purchase Agreement, the Operations and Maintenance Agreement, the Interconnection and Operating Agreement and the System Operations and Dispatch Agreement;

(s) "**Initial Agreement**" means the Limited Partnership Agreement between the **General Partner** and the **Initial Limited Partner** signed December 9, 2004;

(t) "**Initial Limited Partner**" means **Hydro**;

(u) "**Integrated Power System**" means **Hydro's** integrated system of hydraulic and thermal electric generation and power transmission facilities owned and operated by **Hydro** or in some circumstances, owned by **Hydro** in partnership with others, which system is interconnected with other power utilities. The **Wuskwatim Project** will be part of the **Integrated Power System**.

(v) "**Interconnection and Operating Agreement**" means the agreement entered into between **Hydro** (Transmission and Distribution Business Unit) and **Hydro** (Power Supply Business Unit) dated May 4, 2005, as amended, and to be subsequently assigned by **Hydro** (Power Supply Business Unit) to the **Limited Partnership**, whereby the **Wuskwatim Project** will be interconnected with the **Integrated Power System**;

(w) "**Limited Partner**" shall mean **Hydro** or **Taskinigahp Power Corporation** for so long as each is a holder of at least one **Unit**;

(x) "**Limited Partnership**" or "**Partnership**" means the Wuskwatim Power Limited Partnership formed pursuant to the **Initial Agreement**, as amended and restated by this **Agreement**, for the purpose of the **Business**;

(y) "**Management Agreement**" means the agreement entered into between the **Partnership** as owner and **Hydro** as contractor in substantially the same form as described in the **PDA**;

(z) "**NCN**" means the Nisichawayasihk Cree Nation;

(aa) "**NCN Adverse Effects Agreement**" means the agreement to be entered into by the **General Partner** on behalf of the **Partnership** and **NCN** and **Hydro** in substantially the same form as described in the **PDA**;

(bb) "**NCN Financing Agreement**" means the agreement to be entered into between **NCN, Taskinigahp Power Corporation** and **Hydro** in substantially the same form as described in the **PDA**;

(cc) "**Net Income**" or "**Net Loss**" in respect of any **Fiscal Year** means, respectively, the income or loss of the **Partnership** for such period determined in accordance with Section 6.07;

(dd) "**Operations and Maintenance Agreement**" means the agreement to be entered into between the **Partnership** as owner and **Hydro** as contractor in substantially the same form as described in the **PDA**;

(ee) "**Ordinary Resolution**" means a resolution passed by **Partners** holding, in the aggregate, a majority of the issued and outstanding **Units**, who, being entitled to do so, vote in person or by proxy at a duly convened meeting of **Partners** or any adjournment thereof or, alternatively, pass such a resolution unanimously in writing in lieu of a meeting;

(ff) "**Partner**" means the **General Partner** or any **Limited Partner** and "**Partners**" means all **Limited Partners** together with the **General Partner**;

(gg) "**Partnership Assets**" means all assets and property, whether tangible or intangible and whether real, personal or mixed, at any time owned legally or beneficially by the **Partnership**;

(hh) "**Person**" means and includes any individual, corporation, partnership, firm, trust or any other form of entity or organization;

(ii) "**Power Purchase Agreement**" means the agreement to be entered into between the **Partnership** as owner and **Hydro** in substantially the same form as described in the **PDA**;

(jj) "**PDA**" means the project development agreement entered into by **Hydro**, **NCN**, **Taskinigahp Power Corporation,** the **General Partner** and the **Partnership** regarding the planning, development and construction of the **Wuskwatim Project** and the operation of the **Business**;

(kk) "**Project Financing Agreement**" means the agreement to be entered into between the **Partnership** and **Hydro** in substantially the same form as described in the **PDA**;

(ll) "**Record of Limited Partners**" means the record required to be maintained by the **General Partner** at the principal place of business of the **Partnership** pursuant to The Business Names Registration Act, C.C.S.M. c. B110;

(mm) "**Refinancing**" means any borrowings made by the **Partnership** for any purpose other than operating purposes, which are secured by a mortgage or other charge on or against the **Partnership's** interest in the **Partnership Assets**;

(nn) "**Refinancing Proceeds**" means the net proceeds resulting from a **Refinancing**;

(oo) "**Registrar and Transfer Agent**" means the **General Partner** or an agent appointed thereby to keep a register of **Limited Partners** and a register of the transfer of **Units**;

(pp) "**Sale**" means the disposition of all or any part of the **Partnership Assets**, whether by way of sale, expropriation or otherwise;

(qq) “**Sale Proceeds**” means:

i) the proceeds resulting from a **Sale**, after deducting the amounts required to discharge or partially discharge any security relating thereto, and/or repay or partially repay loans incurred in respect of the acquisition of any asset of the **Partnership** for which the **Sale Proceeds** are received and all costs incurred as a result of such **Sale**; and

ii) the proceeds of any insurance to the extent not applied to repair, rebuild or replace some or all of the assets held by the **Partnership**;

(rr) “**Special Resolution**” means:

i) a resolution approved by all of the votes cast in person or by proxy at a duly constituted meeting of **Partners** who are entitled to vote or at any adjournment of that meeting, called in accordance with this Agreement; or

ii) a written resolution in one or more counterparts signed by Partners holding in the aggregate all of the **Units** held by those **Partners** who are entitled to vote on that resolution at a meeting;

(ss) “**Subscription Agreement**” means the subscription form and power of attorney attached hereto as Schedule “A”, or as determined by the **General Partner** pursuant to section 5.04 of this **Agreement**;

(tt) “**Subscription Price**” means the price per **Unit** payable by a **Person** to purchase a **Unit** as set forth in section 5.04 of this **Agreement**;

(uu) “**System Operations and Dispatch Agreement**” means the agreement to be entered into between the **Partnership** and **Hydro** in substantially the same form as described in the **PDA**;

(vv) “**Taskinigahp Power Corporation Financing Agreement**” means the agreement to be entered into between **Taskinigahp Power Corporation** as borrower and **Hydro** as lender in substantially the same form as described in the **PDA**, in which it is defined as the TPC Financing Agreement;

(ww) “**Tax Act**” means the *Income Tax Act* (Canada) as amended from time to time;

(xx) “**Taxable Income**” and “**Tax Loss**”, in respect of any tax year means, respectively, the amount of income or loss of the **Partnership** for such period determined in accordance with the provisions of the **Tax Act** (including the amount of taxable capital gains or allowable capital losses, recapture of capital cost allowance or terminal loss, resulting from the disposition of each capital property of the **Partnership** as determined by the **General Partner** in accordance with the provisions of the **Tax Act**);

(yy) “**Term**” has the meaning ascribed thereto in section 2.07 hereof;

(zz) “**Unit**” means one of the units of the **Partnership** representing an interest in the **Partnership** and “**Units**” means all of the units of the **Partnership**;

(aaa) “**Unit Certificate**” means the form of certificate issued by the **Limited Partnership** evidencing the number of **Units** owned by a **Partner** or any certificates issued in replacement thereof in accordance with the provisions of this **Agreement**;

(bbb) “**Wuskwatim Generating Station**” means the proposed hydro-electric generating station forming the **Wuskwatim Project** and consisting of a complex of structures, including the powerhouse, spillway, dam, dyke and transition structures, used in the production of electricity;

(ccc) “**Wuskwatim Project**” means the **Wuskwatim Generating Station** and all related works, excluding the **Wuskwatim Project Related Transmission Facilities**, but including, without limitation, all dams, dykes, channels, control structures, excavations, camps, storage areas, local roads and access road, to be located at Taskinigup Falls near Wuskwatim Lake which, if built, will contribute about 200 megawatts to the **Integrated Power System** through the **Wuskwatim Project Related Transmission Facilities**;

(ddd) “**Wuskwatim Project Related Transmission Facilities**” means the proposed complex of transmission and communication related facilities to be constructed as part of the **Wuskwatim Transmission Project**, including without limitation all transmission lines, switching and transformer stations and the construction power line;

(eee) “**Wuskwatim Transmission Project**” means **Hydro’s** proposed project to develop the **Wuskwatim Project Related Transmission Facilities** and all related works.

Interpretation

1.02 For all purposes of this **Agreement** except as otherwise expressly provided or unless the context otherwise requires:

(a) headings are for convenience of reference only and do not form a part of this **Agreement**, nor are they intended to interpret, define or limit the scope, extent or intent of this **Agreement** or any provision hereof;

(b) all references to currency herein are references to Canadian currency unless otherwise stated;

(c) any reference to a statute shall include and shall be deemed to be a reference to such statute and the regulations made pursuant thereto, with amendments made thereto in force from time to time and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute so referred to or the regulations made pursuant thereto;

(d) any reference to any entity shall include and shall be deemed to be a reference to any entity that is a successor to such entity;

(e) words importing the masculine gender include the feminine or neuter gender and words importing the singular include the plural and vice versa;

(f) the word "including" shall mean "including without limitation" and "includes" shall mean "includes without limitation";

(g) all accounting terms not specifically defined herein shall be construed in accordance with **Generally Accepted Accounting Principles**.

ARTICLE II

THE PARTNERSHIP

Continuation of Partnership

2.01 The **General Partner** and the **Limited Partners** acknowledge and confirm that the **Partnership** was formed pursuant to the **Initial Agreement** and that this **Agreement** is an amendment to and a restatement of the terms of the **Initial Agreement**. The **General Partner** and the **Limited Partners** agree to continue the **Partnership** under the laws of the Province of Manitoba and the **General Partner** agrees to prepare, complete and file the requisite "Change in a Limited Partnership Form" required pursuant to The Business Names Registration Act, C.C.S.M. c. B110 and to do all things and to execute and deliver all such documents, instruments and assurances as may be necessary to qualify, continue and keep in good standing the **Partnership** as a limited partnership. The **General Partner** shall take all necessary actions on the basis of information available to it in order to maintain the status of the **Partnership** as a limited partnership.

Name of the Partnership

2.02 The **Partnership** shall carry on business under the name "Wuskwatim Power Limited Partnership" (or such other name or names as the **General Partner** may from time to time adopt if required to comply with laws of the jurisdictions in which the **Partnership** may conduct business). The **General Partner** shall notify each **Limited Partner** of any change in the name of the **Partnership** within 10 days of such change. The **General Partner** shall hold the **Partnership** out as an entity separate from any other **Person**.

Maintaining Status of Partnership

2.03 The **General Partner** shall be the sole general partner of the **Partnership**, and shall do all things and shall cause to be executed, amended and filed such certificates, declarations, registers, instruments and documents as may be required to reflect the constitution of the **Partnership** and to carry on the **Business** of the **Partnership**, including, without limitation, the maintaining of a **Record of Limited Partners** stating for each **Limited Partner** the information prescribed by The Business

Names Registration Act, C.C.S.M. c. B110. The **General Partner** and each **Limited Partner** shall execute and deliver as promptly as possible any document that may be necessary or desirable to accomplish the purposes of this **Agreement** or to give effect to the formation and continuation of the **Partnership** under any and all applicable laws. The **General Partner** shall take all necessary action to reflect the constitution of the **Partnership**, on the basis of information available to it, in order to maintain the status of the **Partnership** as a limited partnership under the laws of the Province of Manitoba and to maintain the **Partnership** in compliance with the laws of any other governing authority having jurisdiction over the **Partnership**. The **General Partner** covenants and agrees that:

i) The **Partnership** will not carry on any business in any jurisdiction unless the **General Partner** has taken all steps which may be required by the laws of that jurisdiction for the **Limited Partners** to benefit from limited liability to the same extent that **Limited Partners** enjoy limited liability under the **Act**. The **Partnership** will not carry on business in any jurisdiction in which the laws do not recognize the liability of the **Limited Partners** to be limited unless, in the opinion of the **General Partner**, the risks associated with the possible absence of limited liability in that jurisdiction are not significant considering the relevant circumstances.

ii) The **Partnership** will carry on business in a manner so as to ensure to the greatest extent possible the limited liability of the **Limited Partners**, and the **General Partner** will register the **Partnership** in other jurisdictions where the **General Partner** considers it appropriate to do so.

Fiscal Year

2.04 The **Fiscal Year** of the **Partnership** shall begin on the 1st day of April and shall end on the 31st day of March in each and every year or on such other date as the **Limited Partners** may determine by **Ordinary Resolution**.

Business of the Partnership

2.05 The business of the **Partnership** (the "**Business**") is the completion of the planning, construction, ownership, maintenance and operation of the **Wuskwatim Project** and the sale of energy generated by it and any activities incidental or related thereto with a view to making a profit therefrom.

Registered Office and Mailing Address

2.06 The registered office and mailing address of the **Partnership** and the registered office and mailing address of the **General Partner** shall be ~~820 Taylor~~**360 Portage** **Avenue, Winnipeg,** ~~Manitoba~~ **MB** **R3C** ~~2P4.~~**0G8.** The **General Partner** may not change the registered office or mailing address of the **Partnership** without the consent of all **Limited Partners**.

Term

2.07 The term of the **Agreement** (the "**Term**") shall be indefinite, unless the **Partnership** is dissolved in accordance with Article 10. For greater certainty, this **Agreement** is intended to preclude any **Partner** from dissolving the **Partnership** by giving notice to the other **Partners**, except in accordance with the provisions of Article 10.

Representations and Warranties of the General Partner

2.08 The **General Partner** represents and warrants to, and covenants with, each **Limited Partner** that:

(a) the **Partnership** is a valid limited partnership, duly formed under the laws of the Province of Manitoba;

(b) it is and shall continue to be a corporation incorporated and in good standing under the laws of the Province of Manitoba, or any other jurisdiction under which the **General Partner** may continue or under which a successor to the **General Partner** may be incorporated or continue;

(c) it will maintain all registrations in any jurisdiction where the **Business** of the **Partnership** requires such registration necessary for the conduct of the **Business** and, subject to the successful completion of all necessary regulatory reviews, will have and will continue to have all licenses and permits necessary to carry on the **Business** as **General Partner**;

(d) it has and will continue to have the capacity and corporate authority to act as the general partner of the **Partnership** and to perform its obligations under this **Agreement**, and such obligations do not and will not conflict with, nor do they or will they result in a breach of, its articles of incorporation, its by-laws, any resolutions of its directors or shareholders or any agreement to which it is a party or by which it is bound;

(e) the entering into of this **Agreement** by the **General Partner**, and the performance of its obligations under this **Agreement**, do not and will not require the approval or consent of, or any notice to or filing with, any governmental authority except such approvals and consents as: (i) have been obtained on or before the date hereof; or (ii) will be obtained by the **General Partner** prior to such consents and approvals being required in order for the **General Partner** to carry out its duties and covenants hereunder;

(f) it is not, and shall continue not to be, a non-resident of Canada within the meaning of the **Tax Act**;

(g) the **General Partner** has taken and will take all necessary corporate action to authorize the execution, delivery and performance of this **Agreement**, and this **Agreement** constitutes a valid and binding obligation of the **General Partner**, enforceable against the **General Partner** in accordance with the terms of this **Agreement**;

(h) no authorization, consent or approval of, or filing with, or notice to, any **Person** is required in connection with the execution, delivery or performance of this **Agreement** by the **General Partner,** except such authorizations, consents and approvals as: (i) have been obtained on or before the date hereof; or (ii) will be obtained prior to such authorizations, consents and approvals being required in order for the **General Partner** to carry out its duties and covenants hereunder;

(i) there are no actions, suits or proceedings pending or, to the knowledge of the **General Partner**, threatened, against or affecting the **General Partner** or any of its assets or undertaking at law or in equity or before any arbitrator or any governmental authority having jurisdiction which, if determined adversely, could affect adversely the **General Partner**, and the **General Partner** is not in default with respect to any law, regulation, order, writ, judgment, injunction or award of any competent governmental authority, court, arbitrator or instrumentality which would have such an effect.

Representations and Warranties of each Limited Partner

2.09 Each **Limited Partner** represents and warrants to each other **Limited Partner** and to the **General Partner** that it:

(a) is not and shall continue not to be a "non-resident" of Canada within the meaning of the **Tax Act**;

(b) is not and shall not become a "non-Canadian" within the meaning of the Investment Canada Act (Canada);

(c) is legally competent to execute this **Agreement** and all other agreements contemplated hereby and to take all actions required pursuant hereto, and further certifies that all necessary approvals of directors, shareholders, partners, members or otherwise have been given;

(d) shall promptly provide such evidence of its status as the **General Partner** may reasonably request; and

(e) is and shall continue to be a corporation incorporated and in good standing under its jurisdiction of incorporation, which is Manitoba in the case of **Hydro** and **Taskinigahp Power Corporation**.

Covenant on Representations and Warranties

2.10 Each **Limited Partner** covenants and agrees that it will not transfer or purport to transfer its **Units** to any **Person** which would be unable to make the representations and warranties in section 2.09 and will not change its status such that the above representations would at any time be untrue.

Compliance with Laws

2.11 Each **Limited Partner** shall, on request by the **General Partner**, immediately execute all certificates, declarations, instruments and documents necessary to comply with any applicable law or regulation in regard to the formation, continuance, operation or dissolution of the **Partnership** or in connection with the qualification of the **Partnership** to carry on the **Business** or to own the **Partnership Assets**.

Limitation on the Authority of Limited Partners

2.12 No **Partner**, other than the **General Partner**, shall or shall be entitled to:

(a) take part in the management of the **Business** or the **Partnership** or exercise any power in connection with that control or management or transact business on behalf of the **Partnership**;

(b) execute any document, other than those signed in connection with the **Partners** voting on a resolution of the **Partners**, which binds or purports to bind any other **Partner**, the **General Partner** or the **Partnership**;

(c) hold itself out as having the authority or power to bind any other **Partner**, the **General Partner** or the **Partnership**;

(d) have any authority or power to act for or undertake any obligation or responsibility on behalf of any other **Partner**, **General Partner** or the **Partnership**;

(e) bring any action for partition or sale or otherwise in connection with the **Partnership**, or any interest in any property of the **Partnership**, whether real, tangible or intangible, or file or register or permit to be filed, registered or remain undischarged any lien or charge in respect of any property of the **Partnership**;

(f) compel or seek a partition or sale, judicial or otherwise, of any of the assets of the **Partnership** distributed or to be distributed to the **Partners** in kind in accordance with this **Agreement**;

(g) bring any action for the dissolution of the **Partnership**; or

(h) take any action that will jeopardize or eliminate the status of the **Partnership** as a limited partnership or a “Canadian partnership” for the purposes of the **Tax Act**.

Authority of Hydro

2.13 Notwithstanding the provisions of section 2.12 or any other provision of this **Agreement,** but subject always to the receipt of such approvals as may be required under the **PDA** for **Hydro** or any **Affiliate** of **Hydro** to enter into any agreements with the **Partnership** other than the **Hydro Service Agreements**, **Hydro** shall be entitled to perform all acts and do all things necessary or desirable pursuant to the terms of any agreement between **Hydro** and the **Partnership,** including the **Hydro Service Agreements,** provided, however, that no such act or thing shall jeopardize or eliminate the status of the **Partnership** as a limited partnership or a "Canadian partnership" for the purposes of the **Tax Act**.

ARTICLE III

MANAGEMENT OF PARTNERSHIP

Authority of General Partner

3.01 The **General Partner**, subject to the terms of this **Agreement** and to all applicable laws, shall and is authorized to carry on the **Business** of the **Partnership**, with full power and authority to administer, manage, control and operate the **Business** of the **Partnership** and shall and is given all power and authority to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document necessary for and incidental to carrying on the **Business** of the **Partnership** for and on behalf of and in the name of the **Partnership**. The **General Partner** shall have unlimited liability for the debts, liabilities, obligations and losses of the **Partnership** to the extent that they exceed the assets of the **Partnership**, as required by the **Act**.

Powers of General Partner

3.02 Without limiting the generality of section 3.01 and subject to the terms of this **Agreement**, the **General Partner**, acting reasonably, shall carry out the objects, purposes and all of the activities of the **Partnership** and shall manage the **Business** of the **Partnership** and shall have full power and authority for and on behalf of and in the name of the **Partnership** to:

(a) provide overall management, financial and business planning as required in the operation of the **Business**;

(b) negotiate, execute and perform all agreements which require execution by or on behalf of the **Partnership** involving matters or transactions with respect to the **Business**;

(c) subject to any prior approval of the **Limited Partners** required pursuant to the terms of this **Agreement**, cause the **Partnership** to acquire, sell, transfer or otherwise dispose of, mortgage, pledge, encumber, hypothecate or exchange any or all of the **Partnership Assets**;

(d) use the **Partnership Assets** (including, without limitation, cash on hand) for the purpose of furthering the **Business** on such terms as it sees fit, including, without limitation, the financing of the **Business**, the repayment of obligations of the **Partnership**, the conduct of the **Business** and the purchase or acquisition, as

Partnership Assets, of any other assets or interests in properties, as may be deemed appropriate in its sole discretion in connection with the **Partnership's** operations;

(e) open and manage bank accounts in the name of the **Partnership** and spend the capital of the **Partnership** in the exercise of any right or power exercisable by the **General Partner** hereunder;

(f) borrow funds in the name of the **Partnership** from time to time, including without limitation from the **General Partner** or any affiliate of the **General Partner** provided that the rate of interest and any other expenses relative to those borrowings will not, under any circumstances, exceed that which the Partnership could obtain from a Canadian chartered bank with respect to similar borrowings;

(g) draw, make, execute and issue promissory notes, evidences of indebtedness and all other negotiable or non-negotiable instruments;

(h) mortgage, charge, assign, hypothecate, pledge or otherwise create a security interest in all **Partnership Assets**;

(i) subject to section 6.06, establish such reserves as shall be determined to be reasonable in connection with the operation and future needs of the **Business** in order to carry on prudently the **Business**;

(j) see to the sound management of the **Partnership** and to manage, control and develop all the activities of the **Partnership** and take all measures necessary or appropriate for the **Business** of the **Partnership** or ancillary thereto;

(k) maintain, improve, upgrade, expand, acquire or dispose of the **Partnership Assets** from time to time;

(l) incur and pay all costs and expenses in connection with the **Partnership**;

(m) allocate **Net Income** or **Net Losses** and distribute **Distributable Cash** to the **Partners** in accordance with the provisions of this **Agreement**;

(n) employ, retain, engage or dismiss from employment, individuals, agents, representatives or professionals or other persons with the powers and duties upon the terms and for the compensation as in the discretion of the **General Partner** may be necessary or advisable in the carrying on of the **Business**;

(o) engage agents to assist the **General Partner** to carry out its management obligations to the **Partnership** or subcontract administrative functions;

(p) establish advisory committees to provide to it such advice on such matters as it deems appropriate from time to time;

(q) invest cash assets of the **Partnership** that are not immediately required for the **Business** in investments which the **General Partner** considers appropriate;

(r) act as attorney in fact or agent of the **Partnership** in disbursing and collecting moneys for the **Partnership** and in paying debts and fulfilling the obligations of the **Partnership** and handling and settling any claims of the **Partnership**;

(s) commence or defend any action or proceeding in connection with the **Partnership**;

(t) file returns or other documents required by any governmental or like authority;

(u) make any election that may be made under the **Tax Act** or any other legislation;

(v) purchase, lease or otherwise acquire equipment and premises in connection with the **Business**;

(w) retain legal counsel, experts, advisors or consultants as the **General Partner** considers appropriate and rely upon the advice of such persons;

(x) purchase policies of insurance, as it considers appropriate, for the **Business** and to insure against any liabilities or potential liabilities of the **General Partner**, **Limited Partners** and the **Partnership** that arise or may arise from this **Agreement** or in law or in equity, including, without limiting the generality of the foregoing, relating to personal injury or property damage;

(y) execute and carry out the obligations of the **Limited Partnership** under the terms of the **PDA** and in such other agreements as are referred to in the **PDA** or as are otherwise necessary or desirable for the carrying on of the **Business**;

(z) do anything that is in furtherance of or incidental to the **Business** or that is provided for in this **Agreement** and execute, acknowledge and deliver the documents necessary to effectuate any or all of the foregoing or otherwise in connection with the **Business**; and

(aa) conduct business so that no **Persons** dealing with the **Partnership** will be required to enquire into the authority of the **General Partner** to do any act, take any proceeding, make any decision or execute and deliver any instrument, deed, agreement or document for or on behalf of or in the name of the **Partnership**. The **General Partner** will make all reasonable efforts to insert, and to cause agents of the **Partnership** to insert, the following clause in any contracts or agreements to which the **Partnership** is a party or by which it is bound (other than the **PDA**, the **Interconnection and Operating Agreement** and the **NCN Adverse Effects Agreement** provided that this exclusion from the requirement of inserting the following clause in these agreements shall not be construed as detracting from the limited liability of the **Limited Partners** hereunder or thereunder):

"The parties hereto acknowledge that Wuskwatim Power Limited Partnership is a limited partnership formed under the laws of the Province of Manitoba, a limited partner of which is only liable for any of its liabilities or any of its losses to the extent of the amount that the limited partner has contributed or agreed to contribute to the capital of the limited partnership and the limited partner's pro rata share of any undistributed income. The parties hereto acknowledge that the obligations of Wuskwatim Power Limited Partnership shall not be personally binding upon, nor shall resort be had to, the property of any of the limited partners, their heirs, successors and assigns, and that resort shall only be had to the property of the Wuskwatim Power Limited Partnership or the property of its general partner. 5022649 Manitoba Ltd. is the sole general partner of the limited partnership."

Covenants of General Partner

3.03 Subject to the provisions of this **Agreement**, the **General Partner** covenants that:

(a) it will exercise the powers and discharge its duties under this **Agreement** honestly, in good faith, and in the best interests of the **Partnership**;

(b) in carrying out its obligations under this **Agreement**, it will exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances;

(c) it will maintain the confidentiality of financial and other information and data which it may obtain through or on behalf of the **Partnership**, the disclosure of which may adversely affect the interests of the **Partnership** or of a **Limited Partner**, except to the extent that disclosure is permitted as provided in this **Agreement**, is required by law, is required by virtue of the fact that **Hydro** is a Crown Corporation and must present annual financial statements for public review, or is in the best interests of the **Partnership**;

(d) it shall not carry on any operations in addition to its activities as general partner of the **Partnership** and will devote its best efforts to, and for the benefit of, the **Partnership** and will devote as much time as is necessary for the conduct and prudent management of the activities and affairs of the **Partnership**; and

(e) it will do all things and take all actions as may be necessary to ensure and protect, to the extent reasonably possible, the limited liability of the **Limited Partners**.

Conflict of Interest

3.04 Notwithstanding sections 3.03 or 3.09 or any other provision of this **Agreement**, the **Parties** acknowledge that there is an inherent conflict of interest in **Hydro** entering into the **Hydro Service Agreements** with the **Partnership**. The parties agree that the entering into of the

Hydro Service Agreements and the performance by the **General Partner** on behalf of the **Partnership** and **Hydro** of their respective obligations thereunder in accordance with their respective terms shall not constitute a breach by the **General Partner** of its obligations, fiduciary, contractual or otherwise, to the **Partnership**. It is further acknowledged and agreed that, in accordance with the provisions of the **Operations and Maintenance Agreement** and the **System Operations and Dispatch Agreement**, **Hydro**, in performing its functions under the said two agreements only, is entitled to act and may act at any time as **Hydro** in its sole discretion acting in good faith deems advisable in the best interests of the **Integrated Power System** regardless of whether a particular act, or actions, taken by **Hydro** in the best interests of the **Integrated Power System** may be detrimental to the interests of the **Partnership** or constitute a breach by **Hydro** of an agreement between it and the **Partnership**. The parties agree that neither **Hydro** nor the **General Partner** shall be liable to any **Partner** nor to the **Partnership** for any loss or damage of whatever nature the latter may incur as a consequence of the **General Partner** having entered into the **Operations and Maintenance Agreement** and the **System Operations and Dispatch Agreement** or of **Hydro**, acting in good faith, having acted in the best interests of the **Integrated Power System** as described in this section, subject to section 3.08 hereof and the review processes set out in Articles XVIII and XIX, respectively, of the **PDA**.

Other Activities of General Partner, Shareholder or Affiliates

3.05 Notwithstanding any other provision of this **Agreement**, it is expressly understood and agreed that shareholders and **Affiliates** of the **General Partner** may engage in businesses which may be similar to or competitive with those in which the **Partnership** is or might be engaged and neither the **General Partner** nor its shareholders and affiliates shall be required to offer or make available to the **Partnership** any business, other than the **Business**, or investment opportunity which its shareholders and **Affiliates** may acquire or be engaged in for their own account. The validity of a transaction, agreement or payment involving the **Partnership** and the **General Partner's** shareholders or an **Affiliate** is not affected by reason of the relationship between the **General Partner** and its shareholders or **Affiliates** nor by reason of the approval or lack thereof of the transaction, agreement or payment by the directors of the **General Partner**, all or some of whom may be involved personally or as officers or directors of, or otherwise interested in or related to, the **General Partner's** shareholders or **Affiliates**. Subject always to the receipt of such approvals as may be required under section 2.19 of the **PDA** for **Hydro** or any **Affiliate** of **Hydro** to enter into any agreements with the **Partnership** (other than the **Hydro Service Agreements**), the **General Partner** may engage or retain its shareholders or **Affiliates** on behalf of the **Partnership** to provide goods or services to the **Partnership** and may, in its discretion, engage other **Persons** interested in or companies owned by, associated with or affiliated with the **General Partner**, to render on behalf of the **General Partner**, part or all of such generalized and specialized management functions or administrative services as are reasonably required to accomplish the **Business** of the **Partnership.** This section 3.05 is not intended to detract from or limit the fiduciary obligations of the **General Partner** to the **Partnership** and shall not be deemed to do so.

Title to Partnership Assets

3.06 Title to the **Partnership Assets** shall be deemed to be owned by the **Partnership** as an entirety, and no **Partner** individually shall have any ownership interest in the assets of the **Partnership** or any portion thereof. Title to any or all of the **Partnership's** assets shall be held in the name of the **General Partner** for the benefit of the **Partnership** or in such other names as the **General Partner** may determine from time to time. The **General Partner** declares and warrants that any assets of the **Partnership** of which legal title is held in the name of the **General Partner** shall be held by the **General Partner** as agent of the **Partnership** for the use and benefit of the **Partnership** in accordance with the provisions of this **Agreement**. All of the assets of the **Partnership** shall be recorded as the property of the **Partnership** on its books and records, irrespective of the name in which legal title to such assets is held.

Expenses of the General Partner

3.07 The **Partnership** shall be directly responsible for the payment of all **Allowable Operating Expenses** and shall reimburse the **General Partner** for them, to the extent that they are not otherwise recoverable from the revenues of the **Business**, on a monthly basis, or on any other basis as the **General Partner** may determine in its sole and complete discretion, provided that the **General Partner** is not in default of its duties in connection with such expenses.

Limitation of Liability

3.08 The **General Partner** and its officers, directors, shareholders, employees, agents and **Affiliates** shall not be liable to a **Limited Partner** for any act or omission that does not constitute actual fraud, gross negligence or willful misconduct, if the **General Partner** or the **Person** acted in good faith and in a manner the **General Partner**, or the **Person**, believed to be in the interests of the **Partnership** or not opposed to the interests of the **Partnership** or pursuant to section 3.04. The **General Partner** shall indemnify the **Partnership** and the **Limited Partners** for any costs, damages, liabilities or expenses (including legal fees and expenses) suffered or incurred by the **Partnership** or the **Limited Partners** for an act or omission other than in the circumstances where the **General Partner** is excluded from liability in accordance with the immediately preceding sentence or in circumstances wherein **Hydro**, its subsidiaries and employees are either exempt from liability, or liability is limited (in which instances no more than the amounts determined through application of the sections in question shall be paid), pursuant to the provisions of sections 4(4), 13, 23(4), 24(2), 24(3) and 25(5) of the *Hydro Act,* R.S.M. 1987, c. H190 and amendments thereto (in which instances no more than the amounts determined through application of the sections in question shall be paid).

Indemnity

3.09 The **Partnership** shall indemnify the **General Partner** and its officers, directors, shareholders, employees, agents and **Affiliates** for any costs, damages, liabilities or expenses (including legal fees and expenses) suffered or incurred by them arising out of or incidental to the furtherance of the **Business**, except where the **General Partner** is not entitled to indemnity by application of section 3.08 hereof. Nothing in this provision is intended to detract from the limited liability to which the **Limited Partners** are entitled hereunder and under the **Act**.

Limited Liability of Limited Partners

3.10 Subject to the **Act** and the applicable legislation of any other jurisdiction in which the **Partnership** carries on business, and subject further to any act taken or thing done by a **Limited Partner** contrary to the provisions of this **Agreement**, the liability of each **Limited Partner** for the debts, liabilities and obligations of the **Partnership** is limited to the **Limited Partner's Capital Contribution**, plus the **Limited Partner's** *pro rata* share of any undistributed income of the **Partnership**. Where **Limited Partners** have received the return of all or part of their **Capital Contribution**, the **Limited Partners** shall be liable to the **Partnership's** creditors for any amount, not in excess of the amount returned with interest, necessary to discharge the liabilities of the **Partnership** to all creditors who extended credit or whose claims otherwise arose before the return of the **Capital Contribution**. The **General Partner** will operate the **Partnership** to ensure to the greatest extent possible the limited liability of the **Limited Partners** and will indemnify and hold harmless each **Limited Partner** (including former **Limited Partners**) for all costs, expenses, damages or liabilities suffered or incurred by the **Limited Partner** if the limited liability of that **Limited Partner** is lost, but only if that **Limited Partner's** limited liability is lost as a result of the gross negligence, wilful misconduct or fraud of the **General Partner** in performing its duties and obligations under this **Agreement**. Each **Limited Partner** (the "**Breaching Limited Partner**") will indemnify and hold harmless each of the other **Limited Partners** (including former **Limited Partners**) for all costs, expenses, damages or liabilities suffered or incurred by any such other **Limited Partner** if the limited liability of such other **Limited Partner** is lost due to an act or omission of the **Breaching Limited Partner** that constitutes a breach of this **Agreement**, gross negligence, wilful misconduct or fraud.

Power of Attorney

3.11 In consideration of the sum of $10.00, the receipt and sufficiency of which is hereby acknowledged, each **Limited Partner** hereby irrevocably and unconditionally nominates, constitutes and appoints the **General Partner** with full power of substitution, as its true and lawful attorney and agent with full power and authority in its name, place and stead and for its use and benefit to do the following, namely:

(a) make, execute, swear to, sign, acknowledge, deliver and file, including filing for recording at the appropriate public offices, as, when and where required, any and all of the following:

(i) this **Agreement** and all declarations and other instruments necessary to form, qualify or continue and keep in good standing the **Partnership** as a limited partnership under the laws of the Province of Manitoba and any other jurisdiction in which any such documents may be required or desirable;

(ii) all instruments, declarations and certificates necessary to reflect any amendment to this **Agreement** (subject to such approvals as may be required hereunder) or to the constitution of the **Partnership**; and

(iii) all conveyances, agreements and other instruments necessary or desirable to reflect the dissolution and termination of the **Partnership** and the cancellation of any certificates or declarations, subject always to the provisions of this **Agreement**, including Article 10 hereof;

(b) execute and file with any government body or instrumentality thereof of the Government of Canada or a province in Canada or any other governmental authority having jurisdiction any documents necessary to be filed in connection with the **Business**, property, assets and undertaking of the **Partnership**;

(c) execute and deliver this **Agreement** and any amendments to it approved as required under this **Agreement**;

(d) execute and deliver all such other documents or instruments on behalf of and in the name of the **Partnership** and/or the **Limited Partners** as may be deemed necessary or desirable by the **General Partner** to carry out fully the provisions of this **Agreement** and the provisions of any agreements to which it is a party;

(e) prepare, execute and file all income tax, sales tax and other tax forms, returns and elections which the **Partnership** is required to file or which are deemed desirable to be filed by the **General Partner**; and

(f) prepare and execute assignments and transfers of **Units** when necessary or desirable in accordance with the terms of this **Agreement**.

To evidence the foregoing, each **Limited Partner**, in executing a **Subscription Agreement** or in executing the form of transfer of a **Unit**, will have executed a power of attorney containing substantially the same powers set forth above. Each **Limited Partner** hereby declares that the power of attorney granted herein is irrevocable, is a power coupled with an interest, will survive the insolvency of a **Limited Partner** and will survive the assignment (to the extent of the **Limited Partner's** obligations hereunder and with respect to such actions as are necessary to effect the substitution of the assignee as a limited partner in the **Partnership**) by the **Limited Partner** of the whole or any part of the interest of the **Limited Partner** in the **Partnership** and extends to the heirs, executors, administrators, successors and assigns of the **Limited Partner** and may be exercised by the **General Partner** executing on behalf of each **Limited Partner** any instrument with a single signature as attorney and agent for all of them.

This power of attorney shall not revoke any previous general or continuing power of attorney granted by the **Limited Partner** and will not itself be revoked by any future grant of a general or continuing power of attorney by the **Limited Partner**.

This power of attorney shall not be affected by the withdrawal, resignation or deemed resignation of the **General Partner** as general partner for the **Partnership** and, upon substitution therefore of a replacement **General Partner**, may be exercised by such replacement **General Partner** as if it were an original party to this **Agreement**.

Each **Limited Partner** agrees to be bound by any representations and actions made or taken in good faith by the **General Partner** pursuant to such power of attorney in accordance with the terms hereof, and hereby waives any and all defences which may be available to contest, negate or disaffirm the action of the **General Partner** taken in good faith under such power of attorney.

Restrictions on Authority of General Partner

3.12 The **General Partner's** powers and authorities do not extend to any powers, actions or authority enumerated in Section 9.11 unless and until the requisite **Special Resolution** is passed by the applicable **Partners**. The **General Partner** will not:

(a) commingle the funds of the **Partnership** with its own funds or the funds of any of its **Affiliates** or associates or any other **Person**;
(b) dissolve the affairs of the **Partnership**, except in accordance with the provisions of Article 10;
(c) sell, exchange or otherwise dispose of all or substantially all of the assets of the **Partnership**;
(d) except in accordance with Article 4, assign, transfer or otherwise dispose of its entire interest as **General Partner** without approval of the **Limited Partners**; and
(e) enter into any agreement on behalf of the **Partnership** with **Hydro** or an **Affiliate** of Hydro that requires prior approval in accordance with section 2.19 of the **PDA** until such approval is obtained.

ARTICLE IV

WITHDRAWAL OR REMOVAL OF GENERAL PARTNER

Withdrawal of General Partner

4.01 The **General Partner** may withdraw if such withdrawal is approved by **Special Resolution** of the **Limited Partners**.

Deemed Resignation of General Partner

4.02 The **General Partner** shall be deemed to have resigned as the general partner of the **Partnership** in the event of the bankruptcy, dissolution, liquidation or winding-up of the **General Partner** (or the commencement of any act or proceeding in connection therewith which is not contested in good faith by the **General Partner**) or by the appointment by a court of competent jurisdiction of a trustee, receiver or manager of the affairs of all or substantially all of the properties of the **General Partner**. The **General Partner** shall forthwith advise the **Limited Partners** by written notice of the occurrence of any event referred to in this section 4.02. In such circumstances, the **Limited Partners** shall have the right by **Ordinary Resolution,** after consultation, to designate a successor **General Partner**.

No Removal of General Partner

4.03 The **General Partner** may not be removed by the **Partners** as the **General Partner** except by **Special Resolution**. In such circumstances, the **Limited Partners,** after consultation, shall have the right by **Ordinary Resolution** to designate a successor general partner.

Effect of Withdrawal, Deemed Resignation or Removal of General Partner

4.04 In the event of the withdrawal, deemed resignation or the removal of the **General Partner**, as provided herein, the **General Partner** shall cease to be entitled to any allocation of **Net Income** or **Net Loss** provided for herein upon the effective date of such resignation, deemed resignation or removal, but shall be entitled to its share of any allocation of **Net Income** or **Net Loss** up to such date. The withdrawing, resigning or removed **General Partner** shall be, and shall remain liable for all obligations and liabilities incurred by the **Partnership** for which the **General Partner** was liable before such withdrawal, deemed resignation or removal became effective.

Successor General Partner

4.05 A **Special Resolution** recording the withdrawal or removal of the **General Partner** may provide for the nomination and appointment of a successor **General Partner**, and the resolution in that circumstance shall become effective only on the admission of the successor **General Partner** to the **Partnership** in accordance with the provisions of this **Agreement**. Upon the occurrence of the events described in this paragraph, the successor **General Partner** shall continue the **Business** of the **Partnership** without dissolution.

On the admission of a successor **General Partner** to the **Partnership** on the resignation or removal of the **General Partner**, the resigning or retiring **General Partner** will do all things and take all steps to transfer the administration, management, control and operation of the **Business** of the **Partnership** and the books, records and accounts of the **Partnership** to the successor **General Partner** and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

On the resignation or removal of the **General Partner** and the admission of a successor **General Partner**, the resigning, or retiring, **General Partner**, at the cost of the **Partnership**, will transfer title to the **Partnership**'s property to such successor **General Partner** and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer in a timely fashion.

On the resignation or removal of the **General Partner**, the **Partnership** will release and hold harmless the **General Partner** resigning or being removed from any costs, expenses, damages or liabilities suffered or incurred by the **General Partner** as a result of or arising out of events which occur in relation to the **Partnership** after such resignation or removal.

A successor **General Partner** shall not be a "non-resident" of Canada within the meaning of the ***Tax Act*** and will become a party to this **Agreement** and will agree to be bound by all of the provisions of this **Agreement** and to assume the obligations, duties and liabilities of the **General Partner** from the date the new **General Partner** becomes a party to this **Agreement**.

General Partner's Interest

4.06 The **General Partner** shall transfer all, but not less than all, of its **General Partner** interest in the **Partnership** to a successor **General Partner** appointed in accordance with the provisions of this **Agreement** or otherwise with the unanimous consent of the **Limited Partners**, provided in each case that any transferee assumes the rights and duties of the **General Partner** and agrees to be bound by the provisions of this **Agreement**.

Continuity of Partnership

4.07 In the event of the bankruptcy, insolvency, dissolution, liquidation or winding up of the **General Partner**, the **Partnership** shall not terminate but shall be continued by the then newly appointed or admitted **General Partner**.

ARTICLE V

THE UNITS

Number of Units

5.01 Subject to this **Agreement**, the **Partnership** shall be divided into **Units.** Subject to section 5.02, the Units may be sub-divided into such classes as the **General Partner** may determine are necessary or appropriate provided that the prior consent is obtained from any **Limited Partner** owning **Units** at the time of such proposed sub-division. The **Partnership** shall be authorized to issue an unlimited number of **Units**. **Units** may be issued in fractions.

Nature of Unit

5.02 Each issued and outstanding **Unit** shall be equal to each other **Unit** with respect to voting rights, the right to receive distributions from the **Partnership** and otherwise. No **Unit** shall have any preference or right in any circumstances over any other **Unit**. Each **Unit** carries the right to one vote in respect of all matters to be decided by the **Limited Partners**. Holders of fractional **Units** shall be entitled to vote as hereinafter provided. **Units** have no preference, exchange, preemptive or redemption rights. Only registered holders of **Units** will be entitled to vote or receive distributions or otherwise to exercise or enjoy the rights of **Limited Partners**.

Unit Certificates

5.03 **Unit Certificates** shall be in such form as is from time to time approved by the **General Partner** and shall be signed by the **General Partner** for and on behalf of the **Partnership**.

Unit Subscription

5.04 For each **Unit** subscribed for a **Person** shall pay to the **Partnership** the sum of $1,000 per **Unit**. The **General Partner** shall subscribe for a nominal number of **Units**, not to exceed 0.01% of the issued **Units**. Unless the Parties otherwise agree, subscriptions for **Units** shall be accepted by the **General Partner** only if they are in compliance with this **Agreement** and the **PDA**. The **General Partner** shall subscribe for, and maintain at all times while it is the general partner of the **Partnership**, such number of **Units** equal to 0.01% of the issued **Units**.

Receipt by Limited Partner

5.05 The receipt of any money, securities or other property from the **Partnership** by a **Person** in whose name any **Units** are recorded, or if such **Units** are recorded in the names of more than one **Person**, the receipt thereof by any one of such **Persons**, or by the duly authorized agent of any such **Person** in that regard, shall be a sufficient and proper discharge for that amount of money, securities and other property payable or deliverable in respect of such **Units**.

Registrar and Transfer Agent

5.06 The **General Partner**, or such other **Person** as may be appointed from time to time by the **General Partner**, shall act as **Registrar and Transfer Agent** of the **Partnership** and shall maintain such books as are necessary to record the names and addresses of the **Limited Partners**, the number of **Units** held by each **Limited Partner** and particulars of the transfer of **Units**. The **General Partner** shall cause the **Registrar and Transfer Agent** to perform all duties usually performed by a registrar and transfer agent of certificates of shares in a corporation except as the same may be modified by reason of the nature of the **Units**.

For so long as the **General Partner** shall be **Registrar and Transfer Agent**, the register of **Limited Partners** will be kept by the **General Partner** at its registered office.

Inspection of Records

5.07 The **General Partner** shall cause the **Registrar and Transfer Agent** to make the records relating to the **Limited Partners** available for inspection by any **Limited Partner**, or his agent duly authorized in writing, at the expense of such **Limited Partner**. A copy of the register of the **Limited Partners** shall be provided to any **Limited Partner** on forty-eight [48] hours notice in writing to the **Registrar and Transfer Agent**, at the expense of the **Limited Partner** requesting same.

Transfer of Units

5.08 **Partners** shall not transfer any **Units** owned by them without the unanimous consent of all **Limited Partners**, which consent can be unreasonably withheld except, no consent shall be required in the case of transfers of **Units** between **Hydro** and **Taskinigahp Power Corporation** and transfers of **Units** from the **General Partner** to a successor **General Partner** appointed in accordance with the provisions of this **Agreement,** and the refusal to consent must be reasonable in the case of transfers from **Taskinigahp Power Corporation** to another wholly owned subsidiary of **NCN** or from **Hydro** to another entity wholly owned by **Hydro**. The **General Partner** shall effect any transfer of **Units** required pursuant to the exercise of any sale or purchase right conferred upon **Hydro** or Taskinigahp Power Corporation, as the case may be, in the **Taskinigaph Power Corporation Financing Agreement**.

Restriction on Pledge of Unit(s)

5.09 Save and except for the provisions of the **NCN Financing Agreement,** the **Taskinigahp Power Corporation Financing Agreement** and the **Revenue Advances Consolidation Agreement** as described in the **PDA, Limited Partners** shall not pledge, encumber or assign their **Units** or their interests in their respective capital accounts without the unanimous consent of all **Limited Partners,** which consent can be unreasonably withheld.

Parties Not Bound To See To Trust or Equity

5.10 Except where specific provision has been made therefore in this **Agreement** or a related agreement, including such related finance agreements as may be entered into between **Hydro** and **NCN** and/or **Taskinigahp Power Corporation**, the **Registrar and Transfer Agent** may not be bound to see to the execution of any trust, express, implied or constructive, or any charge, pledge or equity to which any **Unit** or any interest therein is subject or to ascertain or inquire whether any sale or transfer of any such **Unit** or interest therein by a **Limited Partner** or his personal representative is authorized by such trust, charge, pledge or equity, or to recognize any **Person** having any interest therein except for the **Person** or **Persons** recorded as such **Limited Partner**.

Insolvency or Bankruptcy

5.11 In the event of the incapacity, death, insolvency or bankruptcy of a **Limited Partner**, the remaining **Limited Partners** shall have the right, if they so elect, to purchase the **Units** of the **Limited Partner** so incapacitated, deceased, insolvent or bankrupt for a price equal to the fair market value of such **Units** less the amount of any outstanding indebtedness in respect of such **Units** which would have to be paid to obtain the full release of any security interest in such **Units** and after making such adjustments as are reasonable on account of the limited market for the sale of the **Units** and the fact that such sale, in some circumstances, would amount only to a disposition of the minority interest in the **Partnership**, all as determined by an independent third party with expertise in the generation and sale of electricity at the time of disposition.

Lost Unit Certificates

5.12 Where a **Limited Partner** claims that the **Unit Certificate** for its **Units** has been defaced, lost, apparently destroyed or wrongly taken, the **Registrar and Transfer Agent** shall cause a new **Unit Certificate** to be issued, provided that the **Limited Partner** files with the **Registrar and Transfer Agent** a proof of loss in a form satisfactory to the **General Partner** to protect the **Registrar and Transfer Agent** and the **Partnership** from any claimants producing the lost **Unit Certificate** and provided further that the **Limited Partner** satisfies all other reasonable requirements imposed by the **Registrar and Transfer Agent**.

ARTICLE VI

CONTRIBUTIONS, ALLOCATIONS AND DISTRIBUTIONS

Capital Contribution

6.01 The capital of the **Partnership** shall be the aggregate amount of the **Capital Contributions** made by all of the **Partners** from time to time.

Separate Capital Accounts

6.02 There shall be established on the books of the **Partnership** a separate capital account for each **Partner** and each **Partner** shall be credited with the amount of its **Capital Contribution** to the **Partnership**. The capital account of each **Partner** shall be increased by the **Partner's** share of **Net Income** for each **Fiscal Year** and any additional **Capital Contributions**, and shall be decreased by distributions to the **Partner** and **Partner's** share of **Net Loss** for any **Fiscal Year**. No **Partner** shall be entitled to withdraw any part of its capital account or to receive any distribution on return of its **Capital Contribution** except as provided in this **Agreement**. The interest of a **Partner** in the **Partnership** shall not terminate by reason of a negative balance in its capital account.

Additional Capital Contributions

6.03 The **General Partner** shall be entitled to call upon the **Partners** to make additional cash contributions by way of capital investment in the **Partnership** in pro rata amounts in accordance with the number of **Units** owned by each **Partner** on the date of such call. ~~The **General Partner** shall be entitled~~ In determining whether to make a call and the amount of the cash contribution required of the **Partners** in respect of that call the **General Partner** shall, acting honestly and in good faith, consider:

(i) the best interests of the **Partnership**;

(ii) the effect of the call and the amount of the cash contribution on each of the **Limited Partners** including the extent to which the call may dilute the interest of a **Partner**;

(iii) the current and desired **Debt Ratio** of the **Partnership**;

(iv) the amount of reserves currently being maintained by the **General Partner** for the **Partnership**, if any and the desired reserves;

(v) the cost of borrowing funds in the name of the **Partnership**; and

(vi) the amount of **Distributable Cash** of the **Partnership**, if any.

After considering the factors in clauses (i) to (vi), the **General Partner** shall decide whether to call for such additional cash contributions ~~at any time and from time to time~~ as the **General Partner**, ~~in its sole discretion,~~ acting reasonably, determines are necessary or desirable for the operation of the **Business**, including, without limiting the generality of the foregoing, cash for the costs of ~~construction of the **Wuskwatim Project**, cash for the costs of~~ operating and maintaining ~~and operating~~ the **Wuskwatim Project** ~~once it is constructed, and cash for maintaining the **Debt Ratio** of the **Partnership**~~.

If each **Partner** contributes its pro rata amount of any cash contribution demanded of it by the **General Partner** within 90 days of such demand having been received, such cash contribution will be allocated to each **Partner's** respective capital account and each **Partner** shall be issued additional **Units** in the **Partnership** in a number calculated by taking the amount contributed by such **Partner** within the 90-day period pursuant to the demand by the **General Partner** and dividing it by $1,000.00.

In the event that any **Partner** (the "**Defaulting Partner**") does not contribute the full amount demanded of it by the **General Partner** within 90 days of receiving such demand (provided that the amount demanded of such **Defaulting Partner** does not exceed an amount calculated by multiplying the aggregate amount demanded of all **Partners** by a fraction, the numerator of which is the number of **Units** owned by the **Defaulting Partner** prior to the demand, and the denominator of which is the total number of issued **Units** in the **Partnership** prior to the demand), then each of the **Partners** (including the **Defaulting Partner**) shall be issued additional **Units** in the **Partnership** in a number calculated by taking the amount contributed by such **Partner** within the 90-day period pursuant to the demand by the **General Partner** and dividing it by $1,000.00.

Hydro agrees that it shall ensure that at all times while there is one or more **Limited Partners** other than **Hydro** and the **General Partner** is a subsidiary or **Affiliate** of **Hydro**, **Hydro** shall cause the **General Partner** to make all of its **Capital Contributions** pursuant to any demand hereunder so as to maintain the **General Partner's** proportionate ownership of **Units** at a percentage not less than 0.01%.

No Interest Payable

6.04 No interest shall be payable to any **Partner** on account of its **Capital Contribution** by the **Partnership**.

Debt Ratio

6.05 ~~The~~Subject to section 6.03, the General Partner shall ~~at all times maintain the **Partnership** at a **Debt Ratio** of not greater than 75%, provided that, in the first ten years following the **Final Closing**, the **General Partner** will allow~~maintain the **Debt Ratio** of the **Partnership** ~~to increase to as high as 85% to reduce the amount of cash required to be invested by the **Partners** during those years.~~at the percentage the **General Partner**, acting reasonably, honestly and in good faith considers advisable. The **Debt Ratio** shall be calculated to the nearest full percentage point when decisions regarding the distribution of **Distributable Cash** and regarding cash calls are to be made. The amount of the reserves as determined in accordance with section 6.06 shall not be included in calculating the **Debt Ratio**.

Reserves

6.06 The **General Partner** may cause the **Partnership** to establish reserves for capital expenditures, decommissioning costs and other legitimate business purposes and may set aside such funds for reserves as the **General Partner** shall determine to be reasonable in connection with the current operation and the future needs of the **Partnership** in order to carry on prudently the **Business**. The **General Partner** shall have the right to establish reserves as long as the **General Partner** acts reasonably and in a manner that is consistent with prudent business practices having regard to the purposes for which the reserves were established. Funds set aside as reserves shall not be considered to be a cash distribution. Reserves will be funded only out of the income or capital of the **Partnership** and not by calls for additional cash contributions. Once reserves are established, the **General Partner** need not draw on reserves prior to making calls upon **Partners** for additional cash contributions except where expenditures are required for which the reserves were established. For greater certainty, the **General Partner** shall ensure that income used to fund reserves is allocated as between the **Partners** based on their respective pro rata shares of the **Units** of the **Partnership**. The **General Partner** shall provide the **Partners** within 120 days of the end of each **Fiscal Year** with a written report on how the amount of the reserves was determined, which shall include an estimate of capital expenditures and other costs. The reasonableness of the amount of reserves being held by the **Partnership** may be reviewed in the manner set forth in Article XX of the PDA.

Determination of Net Income and Net Loss

6.07 The **Partnership** shall calculate **Net Income** and **Net Loss** according to the application of **Hydro's** accounting policies and practices, in effect from time to time, in accordance with **Generally Accepted Accounting Principles** as evidenced by an unqualified audit opinion. In the event that the application of **Hydro's** accounting policies and practices results in an inability to get an unqualified audit opinion, then the policies and practices in question will not be followed for the **Partnership**.

Allocation of Net Income and Net Loss

6.08 **Net Income** and **Net Loss** shall be allocated between the **General Partner** and the **Limited Partners** pro rata in accordance with the number of **Units** owned by each of them as of the close of business on the last day of the **Fiscal Year** as determined by the **General Partner** from time to time.

Allocation of Taxable Income and Tax Loss

6.09 In respect of each **Fiscal Year**, **Taxable Income, Tax Losses** and any tax credits due to the **Partnership** shall be allocated among the **Partners** in the same proportion as the allocation of **Net Income** and **Net Loss** as determined in accordance with section 6.08.

Distributions

~~6.10~~ 6.10 Within 120 days of the end of each **Fiscal Year**, the **General Partner** shall provide the **Partners** with a written report showing the **General Partner's** determination of **EBITDA** and

Distributable Cash together with its supporting calculations thereof in reasonable detail. The written report shall include disclosure of the amount of cash held by the **Partnership** and the deductions therefrom in accordance with the definition of **Distributable Cash** to arrive at the **Distributable Cash** for the relevant period. Subject to sections 6.05 and 6.06, ~~and subject to the proviso that there shall be no distributions of **Distributable Cash** at any time prior to the **Final Closing Date** without the unanimous consent of the **Partners**,~~ the **General Partner** shall distribute to the **Partners** the amount of **Distributable Cash** shown on such report within 10 business days of having provided such statement to the **Partners**. Without limiting the **General Partner's** obligation to report on, and distribute, **Distributable Cash** not less than once annually as herein contemplated, the **General Partner** may calculate the amount of and make a distribution thereof in such amounts and at such other time or times as the **General Partner** may determine from time to time, subject always to sections 6.05 and 6.06 ~~and subject to the proviso that there shall be no distributions of **Distributable Cash** at any time prior to the **Final Closing Date** without the unanimous consent of the **Partners**.~~
Each **Partner** shall receive its pro rata share of distributions of **Distributable Cash** made by the **General Partner**, calculated as the amount determined by multiplying the total amount of the distribution by a fraction, in which the numerator is the number of **Units** owned by the **Partner** on the last day of the period for which such distribution is made and the denominator is the total number of **Units** owned by all **Partners** on the same date. Distributions shall not be made subject to any withholding taxes except as may be required by law.

Distributions payable pursuant to this provision will be made by electronic transfer of funds and, in the event of the failure of electronic payment methods, by cheque. Any payment by the **General Partner** to a **Partner** pursuant to this **Agreement** will be deemed to have been made upon the date of the electronic withdrawal of funds from the **General Partner's** bank account or upon the date the cheque clears the **General Partner's** bank account. Upon such payment, the **General Partner** will be discharged from all liability to the Partner in respect of such payment; provided, however, that if the electronic payment fails to deposit funds in a **Partner's** bank account or a cheque is lost or destroyed, then, upon the presentation of evidence satisfactory to the **General Partner** of such failure or loss, together with such indemnity as the **General Partner** may reasonably require, the **General Partner** will make a further electronic transfer or issue a replacement cheque to the **Partner**.

Adjustments

6.11 Any financial statements prepared and certified by the auditors of the **Partnership** as provided in this **Agreement** shall be final, binding and conclusive among the **Partners**, provided that any error or omission therein of which notice is given by any **Partner** to the **General Partner** within 180 days after the receipt of a copy thereof by such **Partner** shall be rectified and all proper adjustments made.

Return of Capital

6.12 The **Partners** shall not be entitled to a return of all or a portion of their **Capital Contributions** except as determined by the **General Partner**.

ARTICLE VII

BOOKS, RECORDS AND FINANCIAL INFORMATION

Books and Records

7.01 The **General Partner** will keep and maintain, or cause to be kept and maintained on behalf of the **Partnership** at its principal place of business, full, complete and accurate books of account and records of the business and affairs of the **Partnership** which will, without limitation, include:

(a) capital accounts for the **Partners**;

(b) **Capital Contributions** of the **Partners**;

(c) a register to record the names and addresses of the **Partners**, the number of **Units** held by each **Partner** and the particulars of registration and assignment of **Units**; ~~and~~

(d) a copy of this **Agreement** and any amendments to it~~.~~; and

(e) a record of all payments made to Taskinigahp Trust.

Inspection by Limited Partners

7.02 Each **Limited Partner** and the duly authorized representative of each **Limited Partner** shall have the right, at any reasonable time during regular business hours and without charge, to obtain from the **General Partner**:

(a) a current list of the name and last known business or mailing address of each **Partner**;

(b) a copy of this **Agreement** and the **Declaration** and all amendments to either of them, together with executed copies of any Powers of Attorney pursuant to which this **Agreement**, and all amendments to it, have been executed;

(c) true and full information regarding the amount of cash and the description and statement of any other property and services contributed by each **Partner** and which each **Partner** has agreed to contribute in the future and the date on which each **Partner** became a **Partner**;

(d) the **Record of Limited Partners**;

(e) copies of all minutes of meetings of the **Partners** and all resolutions in writing of the **Partners** in lieu of meetings; and

(f) any other information regarding the affairs of the **Partnership** as is just and reasonable.

Financial Information

7.03 The **General Partner**, or its agent in that behalf, shall be responsible for the preparation and maintenance of internal financial records and retaining auditors with respect to the preparation of annual **Financial Statements** of the **Partnership** at the end of each **Fiscal Year**. Within five days after the receipt of audited **Financial Statements**, the **General Partner** will forward to each **Partner** appearing in the register as a **Partner** at the end of the **Fiscal Year** an annual report for the **Fiscal Year** containing:

(a) **Financial Statements** for the **Partnership** as at the end of the **Fiscal Year** with comparative **Financial Statements** as at the end of, and for the immediately preceding **Fiscal Year**;

(b) a report of the auditor on the **Financial Statements**;

(c) a report on allocations and distributions to **Partners**;

(d) the amount of reserves being maintained by the **General Partner** for the **Partnership**, and each **Partner's** allocation of such reserves;

(e) the current **Debt Ratio**; and

(f) any other information as is material to the **Business**, in the opinion of the **General Partner** (including any management letter).

The **General Partner** shall cause unaudited, monthly financial statements (also including year-to-date financial information), together with a monthly report providing month-end and year-to-date information in respect of the matters outlined in clauses (c) to (e) above) to be prepared within fifteen [15] days of the end of each month and shall forward copies of them to each **Limited Partner** appearing in the **Record of Limited Partners** as a limited partner at the end of the month to which they relate.

No later than 120 days after the end of each **Fiscal Year** of the **Partnership**, **Financial Statements** shall be prepared and certified by the auditors of the **Partnership**, for and as of the end of such **Fiscal Year**, and such **Financial Statements** shall show the assets and the liabilities of the **Partnership**, all incomes and revenues received and receivable, and all expenses, costs, and charges incurred and paid or payable by the **Partnership** in respect of such **Fiscal Year**, with the resulting **Net Income** or **Net Loss** of the **Partnership** in respect of such **Fiscal Year**, and shall also show the amounts standing to the credit of each of the **Partners** in respect of its capital account and separately in respect of the **Net Income** and **Net Loss** of the **Partnership** which has been allocated to each such **Partner** (which amount shall be set out in an account for such **Partner** called its "current account"), all in accordance with the provisions contained in this **Agreement**. The auditors of the **Partnership** shall be the auditors of **Hydro**.

The cost of preparing all such reports shall be at the **Partnership's** expense. Subject to section 7.04, each **Partner** shall be solely responsible for filing its income tax returns and reporting its share of the **Partnership's Taxable Income** or **Tax Loss**, as the case may be.

In addition to the foregoing reporting, the **General Partner** agrees to provide to each **Limited Partner** copies of the written statements provided monthly by **Hydro** to the **Partnership** in accordance with Section 5.13 of the **Project Financing Agreement**, copies of any notices and statements provided by **Hydro** to the **Partnership** pursuant to the **Project Financing Agreement,** the Access Road User Easement as described in the **PDA**, the Transmission Lease as described in the **PDA** and copies of such other business and financial information as the **General Partner** determines to be reasonable in the circumstances with the objective of keeping the **Limited Partners** informed as to matters of a material nature affecting the **Business** of the **Partnership**.

Tax Matters

7.04 The **Partnership** shall be treated as a limited partnership for federal, provincial and municipal income tax and other tax purposes. The **General Partner** shall prepare, or cause to be prepared, any federal, provincial and municipal tax or information returns required to be filed by the **Partnership** and all financial statements required by each **Partner** to enable the filing of any tax or information return which is required to be filed by such **Partner**.

ARTICLE VIII

AMENDMENTS

Amendments to be Adopted Solely by the General Partner

8.01 The **General Partner** (pursuant to the **General Partner's** Powers of Attorney from the **Limited Partners** described in section 3.07), without the consent or approval at the time of any **Limited Partner** (each **Limited Partner**, by acquiring a **Unit**, being deemed to consent to any amendment pursuant to this section 8.01), may amend any provision of this **Agreement** or the **Declaration**, and execute, swear to, acknowledge, deliver, file and record all documents required or desirable in connection with it to reflect:

(a) the omission, substitution, termination or withdrawal of any **Partner** in accordance with this **Agreement**;

(b) a change that is necessary to qualify the **Partnership** as a limited partnership or a partnership in which the **Limited Partners** have limited liability under the laws of any province or state;

(c) a change that is:

   (i) of an inconsequential nature and does not adversely affect the **Limited Partners** (or any of them) in any material respect; or

(ii) required or specifically contemplated by this **Agreement** to be accomplished by the **General Partner** acting alone;

(d) a change in any provision of this **Agreement** which requires any action to be taken by or on behalf of the **General Partner** or the **Partnership** pursuant to the requirements of applicable law if the provisions of applicable law are amended, modified or revoked so that the taking of action is no longer required. The authority set forth in this paragraph shall specifically include the authority to make amendments to this **Agreement** and to the **Declaration** as the **General Partner** deems necessary or desirable in the event the **Act** is amended to eliminate or change any provision now in effect.

Notwithstanding the foregoing, the unanimous consent of all of the **Partners** shall be required for any amendments to this **Agreement** that: (i) alter the ability of the **Limited Partners** to remove the **General Partner** involuntarily; (ii) change the limited liability of any **Limited Partner**; (iii) change the right of a **Limited Partner** to vote at any meeting; (iv) change the **Partnership** from a limited partnership to a general partnership; (v) reduce the percentage of net income allocable to the **Limited Partners** to below 99.99%;~~ or~~ (vi) adversely affect the rights and obligations of any particular **Limited Partner** without similarly affecting the rights and obligations of all other **Limited Partners**~~.~~ (vii) change the factors to be considered pursuant to Section 6.05 when determining whether a cash contribution is required of the **Partners** or (viii) establishes a fixed **Debt Ratio**.

The **General Partner** shall notify the **Limited Partners** of the full details of any amendment to this **Agreement** that does not require the approval of the **Limited Partners** within 10 days of the effective date of such amendment.

Amendment Procedures

8.02 Except as specifically provided in the preceding paragraph, all amendments to this **Agreement** shall be made solely in accordance with the following procedures:

(a) any amendments to this **Agreement** must be proposed by either:

(i) the **General Partner**, by submitting the text of the proposed amendment to all **Limited Partners** in writing; or

(ii) any **Limited Partner** submitting the text of the proposed amendment in writing to the **Partners**.

(b) The **General Partner** shall, within 10 days after the receipt of any proposed amendment or as soon thereafter as is reasonably practicable, submit the text of the proposed amendment to all **Limited Partners**. The **General Partner** may include in the submission its recommendation as to the proposed amendment.

(c) If any amendment is proposed pursuant to this section the **General Partner** shall seek the written consent of the **Partners** to the amendment or shall call a meeting of the **Partners** in accordance with the provisions of this **Agreement** to consider and vote on the proposed amendment. A proposed amendment shall be effective only if approved by **Special Resolution**, unless a greater or different percentage vote of the **Partners** is required by law or any other provision of this **Agreement**. The **General Partner** shall notify all **Partners** upon final adoption or rejection of any proposed amendment.

ARTICLE IX

MEETINGS

Meetings Called by General Partner

9.01 The **General Partner** may call a meeting of the **Partnership** subject to sections 9.03 and 9.04 at such time and place as it considers appropriate in its absolute discretion for the purpose of considering any matters set forth in the notice of meeting.

Meetings Called by Limited Partners

9.02 Any **Limited Partner** may give to the **General Partner** notice, accompanied by the information required to be provided under paragraph 9.04(b), signed by it requesting a meeting of the **Partnership**. The **General Partner** will, within 30 days of receipt of such notice, convene a meeting, and if it fails to do so, the **Limited Partner** requesting the meeting may convene the meeting by giving notice to the **Partners** in accordance with this **Agreement**, signed by such **Person** as the **Limited Partner** requesting the meeting specifies. Every meeting, however convened, will be conducted in accordance with this **Agreement** and the **Act**.

Place of Meeting

9.03 The annual meeting will be held on a rotational basis, unless otherwise unanimously agreed by the **Partners**, at convenient locations in northern Manitoba and southern Manitoba. Meetings can be attended by telephone conference.

Notice of Meetings

9.04 Notice of any meeting will be given to each **Partner** by prepaid ordinary mail or by personal delivery not less than fourteen [14] days (nor more than forty-five [45] days) prior to such meeting, and will state:

(a) the time, date and place of such meeting; and

(b) in general terms, the nature of the business to be transacted at the meeting in sufficient detail to enable the **Partners** to make a reasoned judgment concerning each matter to be considered at the meeting. A copy of the text of any proposed resolution shall accompany the notice of the meeting.

Corporations and Proxies

9.05 A **Partner** which is a corporation shall appoint by resolution an officer, director or other authorized person as its representative to attend, vote and act on its behalf at a meeting of **Partners**. Any **Limited Partner** entitled to vote at a meeting of **Partners** may vote by proxy if a form of proxy has been received by the **General Partner** or the chairperson of the meeting for verification prior to the time fixed by the **General Partner** preceding the meeting, or any adjournment of the meeting. A proxy purporting to be executed by or on behalf of a **Limited Partner** will be considered to be valid unless challenged at the time of or prior to its exercise. The **Person** challenging the proxy will have the burden of proving to the satisfaction of the chairperson of the meeting that the proxy is invalid and any decision of the chairperson concerning the validity of a proxy will be final. Every proxy will be substantially in the form as may be approved by the **General Partner** or as may be satisfactory to the chairperson of the meeting at which it is sought to be exercised. A vote cast in accordance with the terms of an instrument of proxy will be valid notwithstanding the previous death, incapacity, insolvency or bankruptcy of the **Limited Partner** giving the proxy or the revocation of the proxy unless written notice of that death, incapacity, insolvency, bankruptcy or revocation has been received by the chairperson of the meeting prior to the commencement of the meeting.

Attendance of Others

9.06 Any officer or director of the **General Partner** will be entitled to attend and receive notice of any meeting of **Partners**.

Chairperson

9.07 The **General Partner** may nominate an individual (including an officer, director or shareholder of the **General Partner** and who need not be a **Partner**) to be chairperson of a meeting of **Partners** and the individual nominated by the **General Partner** will be chairperson of such meeting unless the **Partners** elect a chairperson by **Ordinary Resolution**. The position of chairperson at the annual meeting of the **Partners** shall rotate annually between a nominee proposed by **Taskinigahp Power Corporation** and a nominee proposed by **Hydro**.

Quorum

9.08 The quorum for a meeting of **Partners** will consist of all **Partners** being present in person or by proxy; provided however, that if within half an hour after the time fixed for the holding of any meeting of **Partners**, all **Partners** are not present, the meeting, will be held at the same time, and, if available, the same place, not fewer than 10 days nor more than 21 days later (or if that date is not a business day, the first business day after that date), and the **Partner** which requested the meeting will give at least 7 days notice to all **Partners** of the date of the reconvening of the adjourned meeting. Such notice need not set forth the matters to be considered unless they are different from those for which the original meeting was called. At such reconvened meeting the quorum for the meeting will consist of one **Limited Partner** present in person or by proxy holding not less than 50% of the outstanding **Units**. Nothing herein shall detract from the requirement of all **Partners** being present in person or by proxy at any meeting (whether original or adjourned) at which a **Special Resolution** will be proposed for consideration and vote of the **Partners**. **Partners** can attend meetings by telephone conference.

Voting

9.09 Each question submitted to a meeting will be decided on a show of hands unless a **Partner** demands a ballot be executed by each **Partner**, in which case ballots shall be prepared and signed by each **Partner** present in person or by proxy and entitled to vote and such ballots shall be preserved. The Chairperson will be entitled to vote in respect of any **Units** pursuant to which he or she may have been appointed to vote. On any vote at a meeting of **Partners**, a declaration of the chairperson concerning the result of the vote will be conclusive absent demonstrable error.

Subject as hereinafter provided, each **Partner** present at the meeting will have one vote for each **Unit** of which it is registered as the **Unit** holder. A holder of a fractional **Unit** is entitled to one vote upon a show of hands at all meetings at which holders of that class of **Units** is entitled to vote but if a ballot is demanded, the vote of the holder of the fractional **Unit** shall only be counted as a fractional vote in the same fraction as the **Unit** held by it.

A vote requested or required concerning the election of a chairperson or an adjournment will be taken immediately on request and any other matter will be managed at the meeting or an adjournment of the meeting in such manner as the chairperson directs.

Resolutions Binding

9.10 Any resolution passed in accordance with this **Agreement** will be binding on all the **Partners** and their respective heirs, executors, administrators, successors and assigns, whether or not any such **Partner** was present in person or voted against any resolution so passed.

Powers Requiring Special Resolution

9.11 The following powers shall only be exercisable by the **General Partner** upon the Special Resolution of the **Partners**:

(a) selling, exchanging or otherwise disposing of all or substantially all of the assets of the **Partnership**;

(b) continuing the **Partnership** in the event that the **Partnership** is terminated by operation of law;

(c) changing or terminating the business of the **Partnership**;

(d) issuing to any party other than **Hydro** or **Taskinigahp Power Corporation**, or a wholly owned subsidiary of **Hydro** or **NCN**, additional **Units**;

(e) changing the auditors except in the event of a change to Manitoba **Hydro's** auditors;

(f) any amendment of this **Agreement**, except as expressly provided for herein or any amendment, alteration, modification or repeal of any **Special Resolution** previously passed by the **Partners**;

(g) dissolving or terminating the **Partnership**, other than as provided for in this **Agreement**;

(h) a merger or consolidation involving the **Partnership**;

(i) a consolidation, subdivision or reclassification of any **Units**;

(j) adding to, changing or removing any right, privilege, restriction or condition attaching to the **Units** which may reasonably be considered materially adverse to any one or more of the holders of the **Units**;

(k) any change to Article VI, provided that where **Partners** are unable to agree on a proposed change to any part of Article VI, such dispute may be referred to arbitration in accordance with the provisions of this **Agreement** and the **PDA**;

(l) requiring the **General Partner** on behalf of the **Partnership** to enforce any obligation or covenant on the part of any **Limited Partner**; ~~and~~

(m) consenting to any judgment in favour of **Hydro** entered in a court of competent jurisdiction against the **Partnership**~~.~~; and

(n) establishing a fixed **Debt Ratio,** but for greater certainty, this Section 9.11(n) shall not be interpreted as requiring a Special Resolution before the General Partner can request the Partners to make additional cash contributions pursuant to Section 6.03.

Powers Exercisable by Ordinary Resolution

9.12 Any other matters not expressly stated in this **Agreement** (including in section 9.11) to be determined by **Special Resolution** and effected by the **General Partner** or stated in section 8.01 to be effected solely by the General Partner shall be determined by **Ordinary Resolution**.

Minutes

9.13 The **General Partner** will cause minutes to be kept of all proceedings and resolutions passed at every meeting, with copies of any resolutions of the **Partnership** to be made and entered in books to be kept for that purpose, and any minutes, if signed by the chairperson of the meeting, will be deemed to be evidence of the matters stated in them and such meeting will be deemed to have been duly convened and held and all resolutions and proceedings shown in them will be deemed to have been duly passed.

Additional Rules and Procedures

9.14 To the extent that the rules and procedures for the conduct of a meeting of the **Partners** are not prescribed in this **Agreement**, the rules and procedures will be determined by the chairperson of the meeting in accordance with *Robert's Rules of Order*.

Authorized Attendance

9.15 The **General Partner** has the right to authorize the presence of any **Person** at a meeting regardless of whether the **Person** is a **Partner**, providing that **Persons** who are not **Partners** are attending the meeting in connection with the **Business**. With the approval of the **General Partner** that **Person** is entitled to address the meeting. When requested by a **Limited Partner**, the **General Partner** shall authorize the attendance of legal counsel for the **Limited Partner** at any meeting of the **Partners**.

Consent Without Meeting

9.16 Any matter which may be addressed by the **Partners** at a meeting may be addressed by written resolution signed by all of such **Partners** in lieu of holding such meeting. In addition, any action required or permitted by this **Agreement** or any provision of law to be taken at a meeting of the **Partners**, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, shall be signed by all of the **Partners** holding all of the **Units** then issued and outstanding and entitled to vote thereon. Such consent shall have the same effect as a vote of such **Partners** and may be stated as such in any certificate or document.

ARTICLE X

DISSOLUTION AND LIQUIDATION

Events of Dissolution

10.01 The **Partnership** shall be dissolved upon the earliest to occur of any one of the following events:

(a) subject to section 4.02 of this **Agreement**, the bankruptcy, dissolution, liquidation or winding up of the **General Partner**, unless a successor **General Partner** is elected in accordance with this **Agreement** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(b) withdrawal or resignation of the **General Partner** unless a successor **General Partner** is elected in accordance with this **Agreement** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(c) the removal of the **General Partner** in accordance with section 4.03 and the failure to elect a successor **General Partner** in such manner so as to preserve the on-going limited liability of the **Limited Partners**;

(d) except as otherwise provided in this **Agreement**, any other event which would cause a dissolution under the **Act**;

(e) after the passing of a resolution requiring unanimous consent in accordance with paragraph 9.11 (g);

(f) the dissolution of the **Partnership** by operation of law; and

(g) the conversion or reconstitution of the **Partnership** into another form of entity under circumstances permitted by this **Agreement**.

Appointment of Receiver

10.02 Upon the occurrence of an event described in section 10.01, the **General Partner** shall act as the Receiver (the "Receiver") of the **Partnership**. If the **General Partner** is unable or unwilling to act as the Receiver or if the event causing dissolution is set out in section 10.01(a), (b) or (c), the **Partners** shall, by **Ordinary Resolution**, appoint some other appropriate person to act as Receiver. Subject to section 10.03, the Receiver shall proceed diligently to wind up the affairs of the **Partnership** and to liquidate the **Partnership Assets** and to distribute the net proceeds from the sale of the **Partnership Assets** in the priority set out herein unless otherwise required by mandatory provisions of applicable law. During the course of such liquidation, the Receiver shall operate the **Business** and in so doing shall be vested with all the powers and authority of the **General Partner** in relation to the **Partnership** under the terms of this **Agreement**. A Receiver which is not the **General Partner** shall be paid reasonable fees and disbursements incurred in carrying out such duties.

Sale of Partnership Assets

10.03 In the event of dissolution, any sale, liquidation, distribution or other disposition of the **Partnership Assets** shall only be to **Hydro**. Not later than 120 days from a decision by the Receiver to liquidate the **Partnership Assets**, the Receiver shall sell the **Partnership Assets** to **Hydro** and **Hydro** shall purchase the **Partnership Assets** from the Receiver for an amount equal to the fair market value of such assets after making such adjustments as are reasonable on account of the limited market for the sale of the assets, all as determined by an independent third party with expertise in the generation and sale of electricity at the time of sale.

Distribution Upon Dissolution

10.04 In the event of the dissolution of the **Partnership**, the Receiver shall distribute the net proceeds from the sale of the **Partnership Assets** as follows:

(a) first, to pay the expenses of liquidation and the creditors of the **Partnership**;

(b) secondly, to provide such reserves as the Receiver considers necessary for any contingent liabilities, including the costs of foreseeable environmental requirements, of the **Partnership**;

(c) thirdly, to return the balance to the **Partners**, pro rata among them according to the capital accounts of each of them at the time.

Events Not Causing Dissolution

10.05 To the maximum extent permitted by the laws of the Province of Manitoba and notwithstanding any rule of law or equity to the contrary, the **Partnership** shall not be dissolved or terminated by admission of any new **General Partner** or **Limited Partner** or the removal, actual or deemed resignation, death, incompetence, bankruptcy, insolvency, other disability or incapacity, dissolution, liquidation, winding-up or receivership, or the admission, resignation or withdrawal of the **General Partner**, the **Limited Partners** or any **Limited Partner**, except in accordance with this **Agreement**.

Deferring Liquidation

10.06 Subject to section 10.03, upon the occurrence of an event described in section 10.01, the Receiver may defer the liquidation of the **Partnership Assets** or may distribute any of the **Partnership Assets** in kind if the **General Partner** or the Receiver determines that a sale would be impractical or would cause undue loss to the **Limited Partners**.

Reasonable Time for Winding Up

10.07 A reasonable time shall be allowed for the orderly winding up of the **Business** and affairs of the **Partnership** and the liquidation of the **Partnership Assets** pursuant to section 10.02 in order to minimize any losses otherwise attendant upon a winding up.

ARTICLE XI

MISCELLANEOUS

Notices

11.01 Any notice or other written communication which must be given or sent under this **Agreement** shall be deemed to have been validly given and received on the third business day following its sending by first class ordinary mail to the address of the **General Partner** and the **Limited Partners** as follows:

(a) in the case of the **General Partner**, at ~~P.O. Box 815, 820 Taylor~~360 Portage Avenue, Winnipeg, Manitoba R3C ~~2P4 (Fascimile~~0G8 (Facsimile No. 204-474-4947) or any new address as the **General Partner** may give notice of; and

(b) in the case of the **Limited Partners** to the address appearing on the register maintained by the **Registrar and Transfer Agent,** which shall include, where available, a mailing address, facsimile number and electronic mail address for each such **Limited Partner** (a **Limited Partner** may give notice to the **Registrar and Transfer Agent** of a new address for such **Limited Partner**, and the **Registrar and Transfer Agent** shall update the register accordingly).

Notices may be personally delivered or delivered by facsimile or other electronic communication and shall be deemed to be received on the day delivered or, if transmitted, as evidenced by confirmed transmission report.

Further Acts

11.02 The parties hereto agree to execute and deliver such further and other documents and perform and cause to be performed such further and other acts and things as may be necessary or desirable in order to give full effect to this **Agreement** and every part thereof.

Binding Effect

11.03 Subject to the restrictions on assignment and transfer herein contained, this **Agreement** shall inure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators and other legal representatives, successors and assigns.

Severability

11.04 Each provision of this **Agreement** is intended to be severable. If any provision hereof is illegal or invalid, such illegality or invalidity shall not affect the validity of the remainder hereof.

Counterparts

11.05 This **Agreement** may be executed in any number of counterparts (either originally or by facsimile) with the same effect as if all parties hereto had signed the same document. This **Agreement** may also be adopted in any subscription and assignment forms or similar instruments signed by a **Partner**, with the same effect as if such **Partner** had executed a counterpart of this **Agreement**. All counterparts and adopting instruments shall be construed together and shall constitute one and the same agreement.

Time

11.06 Time shall be of the essence.

Governing Law

11.07 This **Agreement** shall be governed by and construed in accordance with the laws of the Province of Manitoba and the laws of Canada applicable therein.

Dispute Resolution

11.08 The parties each agree that any disputes or claims arising out of this **Agreement** (other than a review of reserves established by the **General Partner** under section 6.06 hereof, which shall be carried out in accordance with the process set out in Article XX of the **PDA**), including, for greater certainty, any dispute about whether the General Partner has breached its fiduciary obligations to the **Partnership**, shall be determined solely in accordance with the dispute resolution process set out in Article XXI of the **PDA** and they shall not bring any action, other than pursuant to Article XXI of the **PDA**, against any other party or against the **Limited Partnership.** The parties each agree that they shall not bring any action against any officer or director of the **General Partner**, except where such officer or director has committed fraud or has, by act or omission, done anything in respect of which such officer or director would not be entitled to indemnity from the **General Partner** under The Corporations Act (Manitoba), The Manitoba Hydro Act or such other legislation as may be applicable.

[Execution page follows]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement or caused it to be executed on their behalf by their duly authorized signing officers as of the day and year first above written.

5022649 MANITOBA LTD.

Per: ______________________________

Name: ~~Ken R. F. Adams~~
Title: ~~Chairman~~

TASKINIGAHP POWER CORPORATION

Per: _____________________________________

Name: ~~Jerry Primrose~~
Title: ~~President~~

Per: _____________________________________

Name: ~~William Elvis Thomas~~
Title: ~~Vice-President~~

Per: ______________________________

Name: ~~Shirley L. Linklater~~
Title: ~~Secretary-Treasurer~~

THE MANITOBA HYDRO-ELECTRIC BOARD

Per: _____________________________________

Name: ~~Robert B. Brennan~~
Title: ~~President and Chief Executive Officer~~

Per: _____________________________________

Name: ~~Robert D. Bettner~~
Title: ~~Assistant Corporate Secretary~~

SCHEDULE A

WUSKWATIM POWER LIMITED PARTNERSHIP
SUBSCRIPTION FORM AND POWER OF ATTORNEY

TO: WUSKWATIM POWER LIMITED PARTNERSHIP

The undersigned hereby subscribes for ____________ **Unit**(s) of Wuskwatim Power Limited Partnership (the "Limited Partnership") on the terms and as described in the Second Amended and Restated Limited Partnership Agreement, receipt of which is hereby acknowledged and tenders herewith its cheque in the amount of____________ in full payment of the aggregate subscription price for the said **Unit**(s). The undersigned agrees to be bound, as a party to and as limited partner in the **Partnership**, by the terms and conditions of the Second Amended and Restated Limited Partnership (the "**Agreement**"), as same may be amended from time to time in accordance with its terms, as if the undersigned had executed the **Agreement**.

The undersigned hereby represents, warrants and declares that:

(a) the undersigned is a "resident" of Canada within the meaning of *The Income Tax Act* (Canada);

(b) the undersigned is purchasing the **Units** as principal for its own account and not for the benefit of any other person; and

(c) this subscription agreement has been duly authorized, executed and delivered by and constitutes a legal, valid, binding and enforceable obligation of, the undersigned.

The undersigned hereby irrevocably constitutes and appoints the **General Partner** of the **Partnership**, with full power of substitution, as his or its true and lawful attorney and agent, with full power and authority in his name, place and stead to:

(a) execute, deliver, swear to and record in the appropriate public offices any and all of the following:

(i) the **Agreement**, all declarations and declarations of change required under *The Partnership Act* (Manitoba), *The Business Names Registration Act* (Manitoba) and elsewhere as may be required, and any other instruments and amendments thereto which the **General Partner** deems appropriate or necessary to form, qualify, continue and keep in good standing the **Partnership** as a limited partnership in compliance with the laws of the Province of Manitoba or elsewhere as may be required;

(ii) any instruments, certificates and any amendments thereto necessary to reflect any amendment to the Amended and Restated Limited Partnership Agreement properly approved as required pursuant to the terms of the Amended and Restated Limited Partnership Agreement; and

(iii) any conveyances, agreements and other instruments which the **General Partner** deems appropriate or necessary to reflect the dissolution and termination of the **Partnership** pursuant to the terms of the **Agreement** to be entered into on behalf of each **Partner**, including cancellation of any declarations;

(b) execute and file with any governmental body or instrumentality of the Government of Canada or of a province any documents necessary to be filed in connection with the business, property, assets and undertaking of the **Partnership**;

(c) execute and deliver such documents on behalf of and in the name of the **Partnership** and for the **Partners** as may be necessary to give effect to the purposes of the **Partnership** as described in the **Agreement**;

(d) prepare, execute and file all income tax, sales tax and other tax forms, returns and elections which the **Partnership** is required to file or which are deemed desirable to be filed by the **General Partner**; and

(e) prepare and execute assignments and transfers of **Units** when necessary or desirable in accordance with the terms of the **Agreement**.

The power of attorney granted herein is irrevocable and is a power coupled with an interest and is executed under seal and will survive the legal incapacity or mental incompetence of the undersigned and extend to the heirs, executors, administrators, successors and assigns of the undersigned. The undersigned agrees to be bound by any representation or action made or taken by the **General Partner** pursuant to this power of attorney and hereby waives any and all defences which may be available to contest, negate or disaffirm any action of the **General Partner** taken in good faith under this power of attorney.

IN WITNESS WHEREOF the undersigned has executed this subscription form and power of attorney at Winnipeg, in the Province of Manitoba, this day of , ~~2005.~~20 .

Witness Subscriber

IN WITNESS WHEREOF the Wuskwatim Power Limited Partnership has accepted this subscription form and power of attorney by its **General Partner**, 5022649 Manitoba Ltd., having caused its duly authorized proper officer to execute this subscription form and power of attorney this ____ day of , ~~2005.~~20 .

WUSKWATIM POWER LIMITED PARTNERSHIP
by its **General Partner**, 5022649 Manitoba Ltd.

Per:

Document comparison by Workshare Compare on May-12-15 1:10:40 PM

Input:	
Document 1 ID	PowerDocs://TDSLAW/443635/20
Description	TDSLAW-#443635-v20-Limited_Partnership_Agreement
Document 2 ID	file://C:/Users/nicolel/AppData/Roaming/OpenText/DM/Temp/TDSLAW-#1907766-v15-Amended_and_Restated_Limited_Partnership_Agreement.doc
Description	TDSLAW-#1907766-v15-Amended_and_Restated_Limited_Partnership_Agreement
Rendering set	Standard

Legend:	
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Format change	
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Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
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Deletions	153
Moved from	0
Moved to	0
Style change	0
Format changed	0
Total changes	306